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UNITED STATES SECURITIES AND EXCHANGE COMMISSION  
Washington, D.C. 20549

Form 10-Q

(Mark One)

- QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)  
OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended December 31, 2006

or

- TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)  
OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from \_\_\_\_\_ to \_\_\_\_\_

Commission File Number 1-10042

**Atmos Energy Corporation**

*(Exact name of registrant as specified in its charter)*

**Texas and Virginia**

*(State or other jurisdiction of  
incorporation or organization)*

**75-1743247**

*(IRS employer  
identification no.)*

**Three Lincoln Centre, Suite 1800  
5430 LBJ Freeway, Dallas, Texas**

*(Address of principal executive offices)*

**75240**

*(Zip code)*

**(972) 934-9227**

*(Registrant's telephone number, including area code)*

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes  No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "Accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer  Accelerated Filer  Non-Accelerated Filer

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act) Yes  No

Number of shares outstanding of each of the issuer's classes of common stock, as of January 31, 2007.

<u>Class</u>	<u>Shares Outstanding</u>
No Par Value	88,577,022

## GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
AES	Atmos Energy Services, LLC
APS	Atmos Pipeline and Storage, LLC
Bcf	Billion cubic feet
EITF	Emerging Issues Task Force
FASB	Financial Accounting Standards Board
FIN	FASB Interpretation
Fitch	Fitch Ratings, Ltd.
GRIP	Gas Reliability Infrastructure Program
KPSC	Kentucky Public Service Commission
LGS	Louisiana Gas Service Company and LGS Natural Gas Company, which were acquired July 1, 2001
LPSC	Louisiana Public Service Commission
Mcf	Thousand cubic feet
MMcf	Million cubic feet
Moody's	Moody's Investors Services, Inc.
NYMEX	New York Mercantile Exchange, Inc.
RRC	Railroad Commission of Texas
RSC	Rate Stabilization Clause
S&P	Standard & Poor's Corporation
SEC	United States Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
TRA	Tennessee Regulatory Authority
WNA	Weather Normalization Adjustment

**PART I. FINANCIAL INFORMATION**

**Item 1. Financial Statements**

**ATMOS ENERGY CORPORATION  
CONDENSED CONSOLIDATED BALANCE SHEETS**

	<u>December 31, 2006</u>	<u>September 30, 2006</u>
	(Unaudited)	
	(In thousands, except share data)	
<b>ASSETS</b>		
Property, plant and equipment . . . . .	\$5,162,006	\$5,101,308
Less accumulated depreciation and amortization . . . . .	<u>1,494,091</u>	<u>1,472,152</u>
Net property, plant and equipment . . . . .	3,667,915	3,629,156
Current assets		
Cash and cash equivalents . . . . .	94,406	75,815
Cash held on deposit in margin account . . . . .	—	35,647
Accounts receivable, net . . . . .	766,632	374,629
Gas stored underground . . . . .	520,034	461,502
Other current assets . . . . .	<u>194,566</u>	<u>169,952</u>
Total current assets . . . . .	1,575,638	1,117,545
Goodwill and intangible assets . . . . .	738,369	738,521
Deferred charges and other assets . . . . .	<u>234,473</u>	<u>234,325</u>
	<u>\$6,216,395</u>	<u>\$5,719,547</u>
<b>CAPITALIZATION AND LIABILITIES</b>		
Shareholders' equity		
Common stock, no par value (stated at \$.005 per share); 200,000,000 shares authorized; issued and outstanding; December 31, 2006 — 88,504,847 shares; September 30, 2006 — 81,739,516 shares . . . . .	\$ 442	\$ 409
Additional paid-in capital . . . . .	1,670,487	1,467,240
Retained earnings . . . . .	279,299	224,299
Accumulated other comprehensive loss . . . . .	<u>(29,771)</u>	<u>(43,850)</u>
Shareholders' equity . . . . .	1,920,457	1,648,098
Long-term debt . . . . .	<u>1,878,733</u>	<u>2,180,362</u>
Total capitalization . . . . .	3,799,190	3,828,460
Current liabilities		
Accounts payable and accrued liabilities . . . . .	762,487	345,108
Other current liabilities . . . . .	407,351	388,451
Short-term debt . . . . .	154,471	382,416
Current maturities of long-term debt . . . . .	<u>303,209</u>	<u>3,186</u>
Total current liabilities . . . . .	1,627,518	1,119,161
Deferred income taxes . . . . .	324,296	306,172
Regulatory cost of removal obligation . . . . .	255,321	261,376
Deferred credits and other liabilities . . . . .	<u>210,070</u>	<u>204,378</u>
	<u>\$6,216,395</u>	<u>\$5,719,547</u>

See accompanying notes to condensed consolidated financial statements

**ATMOS ENERGY CORPORATION**  
**CONDENSED CONSOLIDATED STATEMENTS OF INCOME**

	Three Months Ended December 31	
	2006	2005
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Utility segment . . . . .	\$ 964,244	\$1,405,010
Natural gas marketing segment . . . . .	711,694	1,101,845
Pipeline and storage segment . . . . .	49,852	39,712
Other nonutility segment . . . . .	1,353	1,492
Intersegment eliminations . . . . .	<u>(124,510)</u>	<u>(264,239)</u>
	1,602,633	2,283,820
Purchased gas cost		
Utility segment . . . . .	701,676	1,124,829
Natural gas marketing segment . . . . .	648,560	1,075,526
Pipeline and storage segment . . . . .	225	—
Other nonutility segment . . . . .	—	—
Intersegment eliminations . . . . .	<u>(123,420)</u>	<u>(263,125)</u>
	1,227,041	1,937,230
Gross profit . . . . .	375,592	346,590
Operating expenses		
Operation and maintenance . . . . .	115,370	108,217
Depreciation and amortization . . . . .	48,995	43,260
Taxes, other than income . . . . .	<u>40,067</u>	<u>45,416</u>
Total operating expenses . . . . .	<u>204,432</u>	<u>196,893</u>
Operating income . . . . .	171,160	149,697
Miscellaneous income . . . . .	1,579	448
Interest charges . . . . .	<u>39,532</u>	<u>36,189</u>
Income before income taxes . . . . .	133,207	113,956
Income tax expense . . . . .	<u>51,946</u>	<u>42,929</u>
Net income . . . . .	<u>\$ 81,261</u>	<u>\$ 71,027</u>
Basic net income per share . . . . .	<u>\$ 0.98</u>	<u>\$ 0.88</u>
Diluted net income per share . . . . .	<u>\$ 0.97</u>	<u>\$ 0.88</u>
Cash dividends per share . . . . .	<u>\$ 0.320</u>	<u>\$ 0.315</u>
Weighted average shares outstanding:		
Basic . . . . .	<u>82,726</u>	<u>80,259</u>
Diluted . . . . .	<u>83,350</u>	<u>80,722</u>

See accompanying notes to condensed consolidated financial statements

**ATMOS ENERGY CORPORATION**  
**CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS**

	<b>Three Months Ended December 31</b>	
	<b>2006</b>	<b>2005</b>
	<b>(Unaudited)</b>	
	<b>(In thousands)</b>	
<b>Cash Flows From Operating Activities</b>		
Net income . . . . .	\$ 81,261	\$ 71,027
Adjustments to reconcile net income to net cash provided by (used in) operating activities:		
Depreciation and amortization:		
Charged to depreciation and amortization . . . . .	48,995	43,260
Charged to other accounts . . . . .	83	147
Deferred income taxes . . . . .	13,869	20,448
Other . . . . .	4,718	3,680
Net assets / liabilities from risk management activities . . . . .	(34,857)	13,695
Net change in operating assets and liabilities . . . . .	<u>50,900</u>	<u>(347,626)</u>
Net cash provided by (used in) operating activities . . . . .	164,969	(195,369)
<b>Cash Flows From Investing Activities</b>		
Capital expenditures . . . . .	(86,986)	(102,465)
Other, net . . . . .	<u>(1,324)</u>	<u>(1,121)</u>
Net cash used in investing activities . . . . .	(88,310)	(103,586)
<b>Cash Flows From Financing Activities</b>		
Net increase (decrease) in short-term debt . . . . .	(227,945)	329,250
Repayment of long-term debt . . . . .	(1,717)	(1,695)
Cash dividends paid . . . . .	(26,261)	(25,429)
Issuance of common stock . . . . .	5,594	6,164
Net proceeds from equity offering . . . . .	<u>192,261</u>	<u>—</u>
Net cash provided by (used in) financing activities . . . . .	(58,068)	308,290
Net increase in cash and cash equivalents . . . . .	18,591	9,335
Cash and cash equivalents at beginning of period . . . . .	<u>75,815</u>	<u>40,116</u>
Cash and cash equivalents at end of period . . . . .	<u>\$ 94,406</u>	<u>\$ 49,451</u>

See accompanying notes to condensed consolidated financial statements

**ATMOS ENERGY CORPORATION**  
**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS**  
**(Unaudited)**  
**December 31, 2006**

**1. Nature of Business**

Atmos Energy Corporation (“Atmos” or “the Company”) and our subsidiaries are engaged primarily in the natural gas utility business as well as other natural gas nonutility businesses. Our natural gas utility business distributes natural gas through sales and transportation arrangements to approximately 3.2 million residential, commercial, public authority and industrial customers throughout our six regulated natural gas utility divisions, in the service areas described below:

<u>Division</u>	<u>Service Area</u>
Atmos Energy Colorado-Kansas Division	Colorado, Kansas, Missouri <sup>(2)</sup>
Atmos Energy Kentucky/Mid-States Division <sup>(1)</sup>	Georgia <sup>(2)</sup> , Illinois <sup>(2)</sup> , Iowa <sup>(2)</sup> , Kentucky, Missouri <sup>(2)</sup> , Tennessee, Virginia <sup>(2)</sup>
Atmos Energy Louisiana Division	Louisiana
Atmos Energy Mid-Tex Division	Texas, including the Dallas/Fort Worth Metroplex
Atmos Energy Mississippi Division	Mississippi
Atmos Energy West Texas Division	West Texas

<sup>(1)</sup> Effective October 1, 2006, the Kentucky and Mid-States Divisions were combined.

<sup>(2)</sup> Denotes locations where we have more limited service areas.

In addition, we transport natural gas for others through our distribution system. Our utility business is subject to federal and state regulation and/or regulation by local authorities in each of the states in which the utility divisions operate. Our shared services division is located in Dallas, Texas, and our customer support centers are located in Amarillo and Waco, Texas.

Our nonutility businesses operate in 22 states and include our natural gas marketing operations, pipeline and storage operations and other nonutility operations. These operations are either organized under or managed by Atmos Energy Holdings, Inc. (AEH), which is wholly-owned by the Company.

Our natural gas marketing operations are managed by Atmos Energy Marketing, LLC (AEM), which is wholly-owned by AEH. AEM provides a variety of natural gas management services to municipalities, natural gas utility systems and industrial natural gas customers, primarily in the southeastern and midwestern states and to our Louisiana and Kentucky/Mid-States utility divisions. These services consist primarily of furnishing natural gas supplies at fixed and market-based prices, contract negotiation and administration, load forecasting, gas storage acquisition and management services, transportation services, peaking sales and balancing services, capacity utilization strategies and gas price hedging through the use of derivative instruments.

Our pipeline and storage business includes the regulated operations of our Atmos Pipeline — Texas Division, a division of Atmos Energy Corporation, and the nonregulated operations of Atmos Pipeline and Storage, LLC (APS), which is wholly-owned by AEH. The Atmos Pipeline — Texas Division transports natural gas to our Atmos Energy Mid-Tex Division and to third parties, as well as manages five underground storage reservoirs in Texas. Through APS, we own or have an interest in underground storage fields in Kentucky and Louisiana. We also use these storage facilities to reduce the need to contract for additional pipeline capacity to meet customer demand during peak periods.

Our other nonutility businesses consist primarily of the operations of Atmos Energy Services, LLC (AES) and Atmos Power Systems, Inc., which are each wholly-owned by AEH. Through AES, we have provided natural gas management services to our utility operations, other than the Mid-Tex Division. These services included aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering the gas to

## ATMOS ENERGY CORPORATION

### NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

our utility service areas at competitive prices. The revenues of AES represent charges to our utility divisions equal to the costs incurred to provide those services. Effective January 1, 2007, our shared services division began providing these services to our utility operations, which were formerly provided by AES. Through Atmos Power Systems, Inc., we have constructed electric peaking power-generating plants and associated facilities and lease these plants through sales-type lease agreements.

#### **2. Unaudited Interim Financial Information**

In the opinion of management, all material adjustments (consisting of normal recurring accruals) necessary for a fair presentation have been made to the unaudited consolidated interim-period financial statements. These consolidated interim-period financial statements are condensed as permitted by the instructions to Form 10-Q and should be read in conjunction with the audited consolidated financial statements of Atmos Energy Corporation included in its Annual Report on Form 10-K for the fiscal year ended September 30, 2006. Because of seasonal and other factors, the results of operations for the three-month period ended December 31, 2006 are not indicative of expected results of operations for the full 2007 fiscal year, which ends September 30, 2007.

#### *Significant accounting policies*

Our accounting policies are described in Note 2 to our Annual Report on Form 10-K for the year ended September 30, 2006. There were no significant changes to those accounting policies during the three months ended December 31, 2006.

#### *Regulatory assets and liabilities*

We record certain costs as regulatory assets in accordance with Statement of Financial Accounting Standards (SFAS) 71, *Accounting for the Effects of Certain Types of Regulation*, when future recovery through customer rates is considered probable. Regulatory liabilities are recorded when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. Substantially all of our regulatory assets are recorded as a component of deferred charges and other assets and substantially all of our regulatory liabilities are recorded as a component of deferred credits and other liabilities. Deferred gas costs are recorded either in other current assets or liabilities and the regulatory cost of removal obligation is separately reported.

**ATMOS ENERGY CORPORATION**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

Significant regulatory assets and liabilities as of December 31, 2006 and September 30, 2006 included the following:

	<u>December 31,</u> <u>2006</u>	<u>September 30,</u> <u>2006</u>
	<u>(In thousands)</u>	
<b>Regulatory assets:</b>		
Merger and integration costs, net . . . . .	\$ 8,541	\$ 8,644
Deferred gas cost . . . . .	86,024	44,992
Environmental costs . . . . .	1,234	1,234
Rate case costs . . . . .	11,318	10,579
Deferred franchise fees . . . . .	1,004	1,311
Other . . . . .	<u>8,065</u>	<u>9,055</u>
	<u>\$116,186</u>	<u>\$ 75,815</u>
<b>Regulatory liabilities:</b>		
Deferred gas cost . . . . .	\$ 15,498	\$ 68,959
Regulatory cost of removal obligation . . . . .	276,300	276,490
Deferred income taxes, net . . . . .	235	235
Other . . . . .	<u>10,320</u>	<u>10,825</u>
	<u>\$302,353</u>	<u>\$356,509</u>

Currently, our authorized rates do not include a return on certain of our merger and integration costs; however, we recover the amortization of these costs. Merger and integration costs, net, are generally amortized on a straight-line basis over estimated useful lives ranging up to 20 years. Environmental costs have been deferred to be included in future rate filings in accordance with rulings received from various state regulatory commissions.

***Comprehensive income***

The following table presents the components of comprehensive income, net of related tax, for the three-month periods ended December 31, 2006 and 2005:

	<u>Three Months Ended</u> <u>December 31</u>	
	<u>2006</u>	<u>2005</u>
	<u>(In thousands)</u>	
Net income . . . . .	\$81,261	\$ 71,027
Unrealized holding gains on investments, net of tax expense of \$883 and \$248 . . . . .	1,441	405
Amortization of interest rate hedging transactions, net of tax expense of \$528 and \$528 . . . . .	860	860
Net unrealized gains (losses) on commodity hedging transactions, net of tax expense (benefit) of \$7,219 and \$(14,749) . . . . .	<u>11,778</u>	<u>(24,063)</u>
Comprehensive income . . . . .	<u>\$95,340</u>	<u>\$ 48,229</u>

**ATMOS ENERGY CORPORATION**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

Accumulated other comprehensive loss, net of tax, as of December 31, 2006 and September 30, 2006 consisted of the following unrealized gains (losses):

	December 31, 2006	September 30, 2006
(In thousands)		
Accumulated other comprehensive loss:		
Unrealized holding gains on investments . . . . .	\$ 3,007	\$ 1,566
Treasury lock agreements . . . . .	(19,680)	(20,540)
Cash flow hedges . . . . .	<u>(13,098)</u>	<u>(24,876)</u>
	<u>\$ (29,771)</u>	<u>\$ (43,850)</u>

***Recent accounting pronouncements***

In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)*. The new standard makes a significant change to the existing rules by requiring recognition in the balance sheet of the overfunded or underfunded positions of defined benefit pension and other postretirement plans, along with a corresponding noncash, after-tax adjustment to stockholders' equity. Additionally, this standard requires that the measurement date must correspond to the fiscal year end balance sheet date. This standard does not change how net periodic pension and postretirement cost or the projected benefit obligation is determined. The balance sheet recognition guidance of this standard will be effective as of September 30, 2007 and the measurement date provisions of this guidance can be adopted as late as fiscal 2008 for our company.

In June 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109* (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes by establishing standards for measurement and recognition in financial statements of positions taken by an entity in its income tax returns. This interpretation also provides guidance on derecognition of income tax assets and liabilities, classification of current and deferred income tax assets and liabilities, accounting for interest and penalties, accounting for income taxes in interim periods and income tax disclosures. We will be required to apply the provisions of FIN 48 beginning October 1, 2007. We are currently evaluating the impact this standard may have on our financial position, results of operations and cash flows.

**3. Derivative Instruments and Hedging Activities**

We conduct risk management activities through both our utility and natural gas marketing segments. We record our derivatives as a component of risk management assets and liabilities, which are classified as current or noncurrent other assets or liabilities based upon the anticipated settlement date of the underlying derivative. Our determination of the fair value of these derivative financial instruments reflects the estimated amounts that we would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains and losses on open contracts. In our determination of fair value, we consider various factors, including closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts. These risk management assets and liabilities are subject to continuing market risk until the underlying derivative contracts are settled.

**ATMOS ENERGY CORPORATION**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

The following table shows the fair values of our risk management assets and liabilities by segment at December 31, 2006 and September 30, 2006:

	<u>Utility</u>	<u>Natural Gas Marketing</u>	<u>Total</u>
		(In thousands)	
<b>December 31, 2006:</b>			
Assets from risk management activities, current . . . . .	\$ 241	\$68,170	\$ 68,411
Assets from risk management activities, noncurrent . . . . .	—	8,344	8,344
Liabilities from risk management activities, current . . . . .	(33,556)	(1,274)	(34,830)
Liabilities from risk management activities, noncurrent . . . . .	<u>—</u>	<u>(277)</u>	<u>(277)</u>
Net assets (liabilities) . . . . .	<u>\$(33,315)</u>	<u>\$74,963</u>	<u>\$ 41,648</u>
<b>September 30, 2006:</b>			
Assets from risk management activities, current . . . . .	\$ —	\$12,553	\$ 12,553
Assets from risk management activities, noncurrent . . . . .	—	6,186	6,186
Liabilities from risk management activities, current . . . . .	(27,209)	(3,460)	(30,669)
Liabilities from risk management activities, noncurrent . . . . .	<u>—</u>	<u>(276)</u>	<u>(276)</u>
Net assets (liabilities) . . . . .	<u>\$(27,209)</u>	<u>\$15,003</u>	<u>\$(12,206)</u>

*Utility Hedging Activities*

We use a combination of storage, fixed physical contracts and fixed financial contracts to partially insulate us and our customers against gas price volatility during the winter heating season. Because the gains or losses of financial derivatives used in our utility segment ultimately will be recovered through our rates, current period changes in the assets and liabilities from these risk management activities are recorded as a component of deferred gas costs in accordance with SFAS 71, *Accounting for the Effects of Certain Types of Regulation*. Accordingly, there is no earnings impact to our utility segment as a result of the use of financial derivatives.

*Nonutility Hedging Activities*

AEM manages its exposure to the risk of natural gas price changes through a combination of storage and financial derivatives, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. Our financial derivative activities include fair value hedges to offset changes in the fair value of our natural gas inventory and cash flow hedges to offset anticipated purchases and sales of gas in the future. AEM also utilizes basis swaps and other non-hedge derivative instruments to manage its exposure to market volatility.

For the three-month period ended December 31, 2006, the change in the deferred hedging position in accumulated other comprehensive loss was attributable to decreases in future commodity prices relative to the commodity prices stipulated in the derivative contracts, and the recognition for the three months ended December 31, 2006 of \$21.0 million in net deferred hedging losses in net income when the derivative contracts matured according to their terms. The net deferred hedging loss associated with open cash flow hedges remains subject to market price fluctuations until the positions are either settled under the terms of the hedge contracts or terminated prior to settlement. The majority of the deferred hedging balance as of December 31, 2006 is expected to be recognized in net income in fiscal 2007 along with the corresponding hedged purchases and sales of natural gas. The remainder of the deferred hedging balance is expected to be recognized in net income in fiscal 2008 and beyond.

**ATMOS ENERGY CORPORATION**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

Our hedge ineffectiveness primarily results from differences in the location and timing of the derivative hedging instrument and the hedged item and could materially affect our results as ineffectiveness is recognized in the income statement. Fair value and cash flow hedge ineffectiveness arising from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the hedge instruments is referred to as basis ineffectiveness. Fair value hedge ineffectiveness arising from the timing of the settlement of physical contracts and the settlement of the related fair value hedge is referred to as timing ineffectiveness. Gains and losses arising from basis and timing ineffectiveness for the three months ended December 31, 2006 and 2005 is as follows:

	<b>Three Months Ended</b>	
	<b>December 31</b>	
	<b>2006</b>	<b>2005</b>
	<b>(In thousands)</b>	
Basis ineffectiveness:		
Fair value basis ineffectiveness . . . . .	\$ (646)	\$8,114
Cash flow basis ineffectiveness . . . . .	<u>124</u>	<u>982</u>
Total basis ineffectiveness . . . . .	(522)	9,096
Timing ineffectiveness:		
Fair value timing ineffectiveness . . . . .	<u>(1,284)</u>	<u>(439)</u>
Total hedge ineffectiveness . . . . .	<u><u>\$(1,806)</u></u>	<u><u>\$8,657</u></u>

Under our risk management policies, we seek to match our financial derivative positions to our physical storage positions as well as our expected current and future sales and purchase obligations to maintain no open positions at the end of each trading day. The determination of our net open position as of any day, however, requires us to make assumptions as to future circumstances, including the use of gas by our customers in relation to our anticipated storage and market positions. Because the price risk associated with any net open position at the end of each day may increase if the assumptions are not realized, we review these assumptions as part of our daily monitoring activities. We may also be affected by intraday fluctuations of gas prices, since the price of natural gas purchased or sold for future delivery earlier in the day may not be hedged until later in the day. At times, limited net open positions related to our existing and anticipated commitments may occur. At the close of business on December 31, 2006, AEH had a net open position (including existing storage) of less than 0.1 Bcf.

**ATMOS ENERGY CORPORATION**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

**4. Debt**

***Long-term debt***

Long-term debt at December 31, 2006 and September 30, 2006 consisted of the following:

	<b>December 31, 2006</b>	<b>September 30, 2006</b>
(In thousands)		
Unsecured floating rate Senior Notes, due October 2007 . . . . .	\$ 300,000	\$ 300,000
Unsecured 4.00% Senior Notes, due 2009 . . . . .	400,000	400,000
Unsecured 7.375% Senior Notes, due 2011 . . . . .	350,000	350,000
Unsecured 10% Notes, due 2011 . . . . .	2,303	2,303
Unsecured 5.125% Senior Notes, due 2013 . . . . .	250,000	250,000
Unsecured 4.95% Senior Notes, due 2014 . . . . .	500,000	500,000
Unsecured 5.95% Senior Notes, due 2034 . . . . .	200,000	200,000
<b>Medium term notes</b>		
Series A, 1995-2, 6.27%, due 2010 . . . . .	10,000	10,000
Series A, 1995-1, 6.67%, due 2025 . . . . .	10,000	10,000
Unsecured 6.75% Debentures, due 2028 . . . . .	150,000	150,000
<b>First Mortgage Bonds</b>		
Series P, 10.43% due 2013 . . . . .	7,500	8,750
Other term notes due in installments through 2013 . . . . .	5,358	5,825
Total long-term debt . . . . .	2,185,161	2,186,878
<b>Less:</b>		
Original issue discount on unsecured senior notes and debentures . . .	(3,219)	(3,330)
Current maturities . . . . .	(303,209)	(3,186)
	<b>\$1,878,733</b>	<b>\$2,180,362</b>

Our unsecured floating rate debt bears interest at a rate equal to the three-month LIBOR rate plus 0.375 percent per year. At December 31, 2006, the interest rate on our floating rate debt was 5.749 percent.

***Short-term debt***

At December 31, 2006 and September 30, 2006, there was \$154.5 million and \$382.4 million outstanding under our commercial paper program and bank credit facilities.

***Shelf Registration***

On December 4, 2006, we filed a registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to \$900 million in new common stock and/or debt securities available for issuance, including approximately \$401.5 million of capacity carried over from our prior shelf registration statement filed with the SEC in August 2004. As discussed in Note 5, in December 2006, we sold 6.3 million shares of common stock under the new registration statement, the net proceeds of which were used to reduce short-term debt. As of December 31, 2006, we have approximately \$701 million of availability remaining under the registration statement.

***Credit facilities***

We maintain both committed and uncommitted credit facilities. Borrowings under our uncommitted credit facilities are made on a when-and-as-needed basis at the discretion of the banks. Our credit capacity and the amount

## ATMOS ENERGY CORPORATION

### NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

of unused borrowing capacity are affected by the seasonal nature of the natural gas business and our short-term borrowing requirements, which are typically highest during colder winter months. Our working capital needs can vary significantly due to changes in the price of natural gas and the increased gas supplies required to meet customers' needs during periods of cold weather.

#### *Committed credit facilities*

As of December 31, 2006, we had three short-term committed revolving credit facilities totaling \$918 million. The first facility is a five-year unsecured facility for \$600 million that we entered into in December 2006. This credit facility replaced our \$600 million three-year revolving credit facility entered into in October 2005. The new facility, expiring December 2011, bears interest at a base rate or at the LIBOR rate plus from 0.30 percent to 0.75 percent, based on the Company's credit ratings, and serves as a backup liquidity facility for our \$600 million commercial paper program. At December 31, 2006, there was \$154.5 million outstanding under our commercial paper program.

We have a second unsecured facility in place which is a 364-day facility expiring November 2007, for \$300 million that bears interest at a base rate or at the LIBOR rate plus from 0.30 percent to 0.75 percent, based on the Company's credit ratings. At December 31, 2006, there were no borrowings under this facility.

We have a third unsecured facility in place for \$18 million that bears interest at the Federal Funds rate plus 0.5 percent. This facility expires in March 2007. At December 31, 2006, there were no borrowings under this facility.

The availability of funds under our credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently satisfy. These conditions include our compliance with financial covenants and the continued accuracy of representations and warranties contained in these agreements. We are required by the financial covenants in both our \$600 million five-year credit facility and \$300 million 364-day credit facility to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At December 31, 2006, our total-debt-to-total-capitalization ratio, as defined, was 58 percent. In addition, the fees that we pay on unused amounts under both the \$600 million and \$300 million credit facilities are subject to adjustment depending upon our credit ratings.

#### *Uncommitted credit facilities*

AEM has a \$580 million uncommitted demand working capital credit facility that expires in March 2007. Borrowings under the credit facility can be made either as revolving loans or offshore rate loans. Revolving loan borrowings will bear interest at a floating rate equal to a base rate (defined as the higher of 0.50 percent per annum above the Federal Funds rate or the lender's prime rate) plus 0.25 percent. Offshore rate loan borrowings will bear interest at a floating rate equal to a base rate based upon LIBOR plus an applicable margin, ranging from 1.25 percent to 1.625 percent per annum, depending on the excess tangible net worth of AEM, as defined in the credit facility. Borrowings drawn down under letters of credit issued by the banks will bear interest at a floating rate equal to the base rate, as defined above, plus an applicable margin, which will range from 1.00 percent to 1.875 percent per annum, depending on the excess tangible net worth of AEM and whether the letters of credit are swap-related standby letters of credit.

AEM is required by the financial covenants in the credit facility to maintain a maximum ratio of total liabilities to tangible net worth of 5 to 1, along with minimum levels of net working capital ranging from \$20 million to \$120 million. Additionally, AEM must maintain a minimum tangible net worth ranging from \$21 million to \$121 million, and must not have a maximum cumulative loss from March 30, 2005 exceeding \$4 million to \$23 million, depending on the total amount of borrowing elected from time to time by AEM. At December 31, 2006, AEM's ratio of total liabilities to tangible net worth, as defined, was 1.61 to 1.

At December 31, 2006, there were no borrowings outstanding under this credit facility. However, at December 31, 2006, AEM letters of credit totaling \$153.9 million had been issued under the facility, which

## ATMOS ENERGY CORPORATION

### NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

reduced the amount available by a corresponding amount. The amount available under this credit facility is also limited by various covenants, including covenants based on working capital. Under the most restrictive covenant, the amount available to AEM under this credit facility was \$21.1 million at December 31, 2006. This line of credit is collateralized by substantially all of the assets of AEM and is guaranteed by AEH.

The Company also has an unsecured short-term uncommitted credit line of \$25 million that is used for working-capital and letter-of-credit purposes. There were no borrowings under this uncommitted credit facility at December 31, 2006, but letters of credit reduced the amount available by \$5.4 million. This uncommitted line is renewed or renegotiated at least annually with varying terms, and we pay no fee for the availability of the line. Borrowings under this line are made on a when-and-as-available basis at the discretion of the bank.

AEH, the parent company of AEM, has a \$100 million intercompany uncommitted demand credit facility with the Company which bears interest at LIBOR plus 2.75 percent. State regulators have approved this facility through December 31, 2007 and have authorized an increase in the intercompany facility to \$200 million. At December 31, 2006, there were no borrowings under this facility.

In addition, AEM has a \$120 million intercompany uncommitted demand credit facility with AEH for its nonutility business which bears interest at LIBOR plus 2.75 percent. Any outstanding amounts under this facility are subordinated to AEM's \$580 million uncommitted demand credit facility described above. This facility is used to supplement AEM's \$580 million credit facility. At December 31, 2006, there were no borrowings under this facility.

#### *Debt Covenants*

We have other covenants in addition to those described above. Our Series P First Mortgage Bonds contain provisions that allow us to prepay the outstanding balance in whole at any time, after November 2007, subject to a prepayment premium. The First Mortgage Bonds provide for certain cash flow requirements and restrictions on additional indebtedness, sale of assets and payment of dividends. Under the most restrictive of such covenants, cumulative cash dividends paid after December 31, 1985 may not exceed the sum of accumulated net income for periods after December 31, 1985 plus \$9 million. At December 31, 2006 approximately \$258.3 million of retained earnings was unrestricted with respect to the payment of dividends.

We were in compliance with all of our debt covenants as of December 31, 2006. If we were unable to comply with our debt covenants, we could be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions. Our two public debt indentures relating to our senior notes and debentures, as well as our \$600 million and \$300 million revolving credit agreements, each contain a default provision that is triggered if outstanding indebtedness arising out of any other credit agreements in amounts ranging from in excess of \$15 million to in excess of \$100 million becomes due by acceleration or is not paid at maturity. In addition, AEM's credit agreement contains a cross-default provision whereby AEM would be in default if it defaults on other indebtedness, as defined, by at least \$250 thousand in the aggregate. Additionally, this agreement contains a provision that would limit the amount of credit available if Atmos were downgraded below an S&P rating of BBB and a Moody's rating of Baa2.

Except as described above, we have no triggering events in our debt instruments that are tied to changes in specified credit ratings or stock price, nor have we entered into any transactions that would require us to issue equity, based on our credit rating or other triggering events.

#### **5. Public Offering**

On December 13, 2006, we completed the public offering of 6,325,000 shares of our common stock including the underwriters' exercise of their overallotment option of 825,000 shares. The offering was priced at \$31.50 and generated net proceeds of approximately \$192 million. We used the net proceeds from this offering to reduce short-term debt.

**ATMOS ENERGY CORPORATION**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

**6. Earnings Per Share**

Basic and diluted earnings per share for the three months ended December 31, 2006 and 2005 are calculated as follows:

	<b>Three Months Ended December 31</b>	
	<b>2006</b>	<b>2005</b>
	<b>(In thousands, except per share amounts)</b>	
Net income . . . . .	<u>\$81,261</u>	<u>\$71,027</u>
Denominator for basic income per share — weighted average common shares . .	82,726	80,259
Effect of dilutive securities:		
Restricted and other shares . . . . .	453	365
Stock options . . . . .	<u>171</u>	<u>98</u>
Denominator for diluted income per share — weighted average common shares . . . . .	<u>83,350</u>	<u>80,722</u>
Income per share — basic . . . . .	<u>\$ 0.98</u>	<u>\$ 0.88</u>
Income per share — diluted . . . . .	<u>\$ 0.97</u>	<u>\$ 0.88</u>

There were no out-of-the-money options excluded from the computation of diluted earnings per share for the three months ended December 31, 2006 and 2005 as their exercise price was less than the average market price of the common stock during that period.

**7. Interim Pension and Other Postretirement Benefit Plan Information**

The components of our net periodic pension cost for our pension and other postretirement benefit plans for the three months ended December 31, 2006 and 2005 are presented in the following table. All of these costs are recoverable through our gas utility rates; however, a portion of these costs is capitalized into our utility rate base. The remaining costs are recorded as a component of operation and maintenance expense.

	<b>Three Months Ended December 31</b>			
	<b>Pension Benefits</b>		<b>Other Benefits</b>	
	<b>2006</b>	<b>2005</b>	<b>2006</b>	<b>2005</b>
	<b>(In thousands)</b>			
Components of net periodic pension cost:				
Service cost . . . . .	\$ 4,018	\$ 4,117	\$2,807	\$3,271
Interest cost . . . . .	6,495	5,722	2,640	2,210
Expected return on assets . . . . .	(6,089)	(6,400)	(597)	(547)
Amortization of transition asset . . . . .	—	—	378	378
Amortization of prior service cost . . . . .	45	16	8	90
Amortization of actuarial loss . . . . .	<u>2,434</u>	<u>3,299</u>	<u>—</u>	<u>320</u>
Net periodic pension cost . . . . .	<u>\$ 6,903</u>	<u>\$ 6,754</u>	<u>\$5,236</u>	<u>\$5,722</u>

**ATMOS ENERGY CORPORATION**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

The assumptions used to develop our net periodic pension cost for the three months ended December 31, 2006 and 2005 are as follows:

	<u>Pension Benefits</u>		<u>Other Benefits</u>	
	<u>2006</u>	<u>2005</u>	<u>2006</u>	<u>2005</u>
Discount rate . . . . .	6.30%	5.00%	6.30%	5.00%
Rate of compensation increase . . . . .	4.00%	4.00%	4.00%	4.00%
Expected return on plan assets . . . . .	8.25%	8.50%	5.20%	5.30%

The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. Generally, our funding policy is to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974. However, additional voluntary contributions are made to satisfy regulatory requirements in certain of our jurisdictions. During the three months ended December 31, 2006, we contributed \$2.8 million to our other postretirement plans, and we expect to contribute a total of approximately \$11 million to these plans during fiscal 2007.

**8. Commitments and Contingencies**

*Litigation and Environmental Matters*

With respect to the specific litigation and environmental-related matters or claims that were disclosed in Note 13 to our annual report on Form 10-K for the year ended September 30, 2006, there were no material changes in the status of such litigation and environmental-related matters or claims during the three months ended December 31, 2006. We continue to believe that the final outcome of such litigation and environmental-related matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

In addition, we are involved in other litigation and environmental-related matters or claims that arise in the ordinary course of our business. While the ultimate results of such litigation and response actions to such environmental-related matters or claims cannot be predicted with certainty, we believe the final outcome of such litigation and response actions will not have a material adverse effect on our financial condition, results of operations or cash flows.

*Purchase Commitments*

AEM has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At December 31, 2006, AEM was committed to purchase 89.5 Bcf within one year and 56.7 Bcf within one to three years under indexed contracts. AEM is committed to purchase 1.6 Bcf within one year and 0.1 Bcf within one to three years under fixed price contracts with prices ranging from \$5.26 to \$12.00. Purchases under these contracts totaled \$420.4 million and \$787.7 million for the three months ended December 31, 2006 and 2005.

Our utility operations, other than the Mid-Tex Division, maintain supply contracts with several vendors that generally cover a period of up to one year. Commitments for estimated base gas volumes are established under these contracts on a monthly basis at contractually negotiated prices. Commitments for incremental daily purchases are made as necessary during the month in accordance with the terms of the individual contract.

**ATMOS ENERGY CORPORATION**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

Our Mid-Tex Division maintains long-term supply contracts to ensure a reliable source of gas for our customers in its service area which obligate it to purchase specified volumes at market prices. The estimated fiscal year commitments under these contracts as of December 31, 2006 are as follows (in thousands):

2007 .....	\$332,401
2008 .....	109,656
2009 .....	9,588
2010 .....	9,189
2011 .....	8,589
Thereafter .....	<u>19,418</u>
	<u>\$488,841</u>

***Regulatory Matters***

In February 2005, the Attorney General of the State of Kentucky filed a complaint with the Kentucky Public Service Commission (KPSC) alleging that our rates were producing revenues in excess of reasonable levels. We answered the complaint and filed a Motion to Dismiss with the KPSC. In February 2006, the KPSC issued an Order denying our Motion to Dismiss but stated that the Attorney General had not met his burden of proof concerning his complaint. In November 2006, we requested dismissal of the case through our filing of a notice of intent to file a general rate case in December 2006. Upon receipt of the notice of intent, the KPSC suspended the procedural schedule until it issues a decision regarding the motion for dismissal. A hearing should be scheduled for early 2007. We believe that the Attorney General will not be able to demonstrate that our present rates are in excess of reasonable levels.

In December 2006, the Company filed a rate application for an increase in base rates of \$10.4 million in Kentucky. Additionally, we proposed to implement a process to review our rates annually and to collect the bad debt portion of gas costs directly rather than through the base rate. A decision is expected in the case in July 2007.

During fiscal 2006, we received “show cause” resolutions from approximately 80 cities served by our Mid-Tex Division, including the City of Dallas, which require the Mid-Tex Division to demonstrate that the existing distribution rates are just and reasonable. In May 2006, the Mid-Tex Division filed a Statement of Intent with the Railroad Commission of Texas (RRC) which consolidated the “show cause” resolutions and seeks incremental annual revenues of approximately \$60 million and several rate design changes including WNA, revenue stabilization and recovery of the gas cost component of bad debt expense. In exchange for an agreement to provide the intervening parties in the case an additional two months to prepare for the hearing, the Mid-Tex Division obtained an agreement and approval to implement WNA in its rates for the 2006-2007 winter season and to implement WNA in the final rates in this proceeding. The hearing was completed on November 17, 2006. The hearing examiners in the case issued their Proposal for Decision (PFD) on February 2, 2007, which contained their recommendations to the RRC. In the PFD, the examiners recommended a total annual decrease in the Mid-Tex Division’s rates of approximately \$22.8 million, a customer refund of \$2.6 million and a permanent weather normalization adjustment mechanism based on 10-year weather data. We are in the process of preparing our responses to the recommendations in the PFD. We continue to believe that the evidence presented in the case supports our request to increase rates in order to earn a fair rate of return. While the RRC is required by statute to issue its final decision by April 2, 2007, it could issue a final order sometime in March 2007. Any rate increase will be effective prospectively from the date of the final order; however, any rate decrease will be effective from May 31, 2006.

In January 2006, the Lubbock, Texas City Council passed a resolution requiring Atmos to submit copies of all documentation necessary for the city to review the rates of Atmos’ West Texas Division to ensure they are just and reasonable. Information was provided to the city in February 2006. We believe that we will be able to ultimately demonstrate to the City of Lubbock that our rates are just and reasonable.

## ATMOS ENERGY CORPORATION

### NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

In May 2006, Atmos began receiving “show cause” ordinances from several of the cities in the West Texas Division. We made a filing in response to the ordinances in October 2006. We believe that we will be able to ultimately demonstrate to the West Texas cities that our rates are just and reasonable.

#### *Other*

In May 2006, we announced plans to form a joint venture and construct a natural gas gathering system in Eastern Kentucky, referred to as the Straight Creek Project. The Company is continuing to evaluate the scale and scope of the original project design, as well as the in-service date.

#### **9. Concentration of Credit Risk**

Information regarding our concentration of credit risk is disclosed in Note 15 to our annual report on Form 10-K for the year ended September 30, 2006. During the three months ended December 31, 2006, there were no material changes in our concentration of credit risk.

#### **10. Segment Information**

Atmos Energy Corporation and our subsidiaries are engaged primarily in the natural gas utility business as well as certain nonutility businesses. We distribute natural gas through sales and transportation arrangements to approximately 3.2 million residential, commercial, public authority and industrial customers throughout our six regulated utility divisions, which cover service areas located in 12 states. In addition, we transport natural gas for others through our distribution system.

Through our nonutility businesses we provide natural gas management and marketing services to industrial customers, municipalities and other local distribution companies located in 22 states. Additionally, we provide natural gas transportation and storage services to certain of our utility operations and to third parties.

Our operations are divided into four segments:

- the utility segment, which includes our regulated natural gas distribution and related sales operations,
- the natural gas marketing segment, which includes a variety of nonregulated natural gas management services,
- the pipeline and storage segment, which includes our regulated and nonregulated natural gas transmission and storage services and
- the other nonutility segment, which includes all of our other nonregulated nonutility operations.

Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers in differing regulatory environments. Although our utility segment operations are geographically dispersed, they are reported as a single segment as each utility division has similar economic characteristics. The accounting policies of the segments are the same as those described in the summary of significant accounting policies found in our annual report on Form 10-K for the fiscal year ended September 30, 2006. We evaluate performance based on net income or loss of the respective operating units.

**ATMOS ENERGY CORPORATION**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

Income statements for the three-month periods ended December 31, 2006 and 2005 by segment are presented in the following tables:

	Three Months Ended December 31, 2006					
	<u>Utility</u>	<u>Natural Gas Marketing</u>	<u>Pipeline and Storage</u>	<u>Other Nonutility</u>	<u>Eliminations</u>	<u>Consolidated</u>
	(In thousands)					
Operating revenues from external parties . . . . .	\$964,083	\$611,369	\$26,775	\$ 406	\$ —	\$1,602,633
Intersegment revenues . . . . .	<u>161</u>	<u>100,325</u>	<u>23,077</u>	<u>947</u>	<u>(124,510)</u>	<u>—</u>
	964,244	711,694	49,852	1,353	(124,510)	1,602,633
Purchased gas cost . . . . .	<u>701,676</u>	<u>648,560</u>	<u>225</u>	<u>—</u>	<u>(123,420)</u>	<u>1,227,041</u>
Gross profit . . . . .	262,568	63,134	49,627	1,353	(1,090)	375,592
Operating expenses						
Operation and maintenance . .	98,113	5,578	11,616	1,239	(1,176)	115,370
Depreciation and amortization . . . . .	43,722	329	4,918	26	—	48,995
Taxes, other than income . . .	<u>37,622</u>	<u>249</u>	<u>2,127</u>	<u>69</u>	<u>—</u>	<u>40,067</u>
Total operating expenses . . . . .	<u>179,457</u>	<u>6,156</u>	<u>18,661</u>	<u>1,334</u>	<u>(1,176)</u>	<u>204,432</u>
Operating income . . . . .	83,111	56,978	30,966	19	86	171,160
Miscellaneous income . . . . .	1,780	1,716	776	453	(3,146)	1,579
Interest charges . . . . .	<u>32,473</u>	<u>1,027</u>	<u>8,421</u>	<u>671</u>	<u>(3,060)</u>	<u>39,532</u>
Income (loss) before income taxes . . . . .	52,418	57,667	23,321	(199)	—	133,207
Income tax expense (benefit) . .	<u>20,584</u>	<u>22,720</u>	<u>8,721</u>	<u>(79)</u>	<u>—</u>	<u>51,946</u>
Net income (loss) . . . . .	<u>\$ 31,834</u>	<u>\$ 34,947</u>	<u>\$14,600</u>	<u>\$ (120)</u>	<u>\$ —</u>	<u>\$ 81,261</u>
Capital expenditures . . . . .	<u>\$ 72,419</u>	<u>\$ 338</u>	<u>\$14,229</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 86,986</u>

**ATMOS ENERGY CORPORATION**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

	Three Months Ended December 31, 2005					
	<u>Utility</u>	<u>Natural Gas Marketing</u>	<u>Pipeline and Storage</u>	<u>Other Nonutility</u>	<u>Eliminations</u>	<u>Consolidated</u>
	(In thousands)					
Operating revenues from external parties . . . . .	\$1,404,806	\$ 860,613	\$17,881	\$ 520	\$ —	\$2,283,820
Intersegment revenues . . . . .	<u>204</u>	<u>241,232</u>	<u>21,831</u>	<u>972</u>	<u>(264,239)</u>	<u>—</u>
	1,405,010	1,101,845	39,712	1,492	(264,239)	2,283,820
Purchased gas cost . . . . .	<u>1,124,829</u>	<u>1,075,526</u>	<u>—</u>	<u>—</u>	<u>(263,125)</u>	<u>1,937,230</u>
Gross profit . . . . .	280,181	26,319	39,712	1,492	(1,114)	346,590
Operating expenses						
Operation and maintenance . . . . .	92,766	4,352	10,998	1,265	(1,164)	108,217
Depreciation and amortization . . . . .	38,264	470	4,502	24	—	43,260
Taxes, other than income . . . . .	<u>42,902</u>	<u>243</u>	<u>2,160</u>	<u>111</u>	<u>—</u>	<u>45,416</u>
Total operating expenses . . . . .	<u>173,932</u>	<u>5,065</u>	<u>17,660</u>	<u>1,400</u>	<u>(1,164)</u>	<u>196,893</u>
Operating income . . . . .	106,249	21,254	22,052	92	50	149,697
Miscellaneous income . . . . .	2,837	590	1,405	661	(5,045)	448
Interest charges . . . . .	<u>31,588</u>	<u>2,862</u>	<u>5,973</u>	<u>761</u>	<u>(4,995)</u>	<u>36,189</u>
Income (loss) before income taxes . . . . .	77,498	18,982	17,484	(8)	—	113,956
Income tax expense (benefit) . . . . .	<u>29,085</u>	<u>7,530</u>	<u>6,317</u>	<u>(3)</u>	<u>—</u>	<u>42,929</u>
Net income (loss) . . . . .	<u>\$ 48,413</u>	<u>\$ 11,452</u>	<u>\$11,167</u>	<u>\$ (5)</u>	<u>\$ —</u>	<u>\$ 71,027</u>
Capital expenditures . . . . .	<u>\$ 72,415</u>	<u>\$ 332</u>	<u>\$29,718</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 102,465</u>

**ATMOS ENERGY CORPORATION**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

Balance sheet information at December 31, 2006 and September 30, 2006 by segment is presented in the following tables:

	December 31, 2006					
	Utility	Natural Gas Marketing	Pipeline and Storage  (In thousands)	Other Nonutility	Eliminations	Consolidated
<b>ASSETS</b>						
Property, plant and equipment, net. . . . .	\$3,112,635	\$ 7,693	\$546,329	\$ 1,258	\$ —	\$3,667,915
Investment in subsidiaries . . . . .	342,347	(2,155)	—	—	(340,192)	—
Current assets						
Cash and cash equivalents . . . . .	20,825	66,626	—	6,955	—	94,406
Cash held on deposit in margin account. . . . .	—	—	—	—	—	—
Assets from risk management activities . . . . .	241	68,362	33,125	—	(33,317)	68,411
Other current assets . . . . .	958,929	459,212	29,346	7,934	(42,600)	1,412,821
Intercompany receivables . . . . .	590,431	—	—	13,431	(603,862)	—
Total current assets. . . . .	<u>1,570,426</u>	<u>594,200</u>	<u>62,471</u>	<u>28,320</u>	<u>(679,779)</u>	<u>1,575,638</u>
Intangible assets . . . . .	—	3,000	—	—	—	3,000
Goodwill. . . . .	567,221	24,282	143,866	—	—	735,369
Noncurrent assets from risk management activities . . . . .	—	8,345	1	—	(2)	8,344
Deferred charges and other assets. . . . .	<u>203,499</u>	<u>1,270</u>	<u>5,163</u>	<u>16,197</u>	<u>—</u>	<u>226,129</u>
	<u><u>\$5,796,128</u></u>	<u><u>\$636,635</u></u>	<u><u>\$757,830</u></u>	<u><u>\$45,775</u></u>	<u><u>\$(1,019,973)</u></u>	<u><u>\$6,216,395</u></u>
<b>CAPITALIZATION AND LIABILITIES</b>						
Shareholders' equity . . . . .	\$1,920,457	\$179,538	\$129,289	\$33,520	\$ (342,347)	\$1,920,457
Long-term debt . . . . .	<u>1,875,334</u>	<u>—</u>	<u>—</u>	<u>3,399</u>	<u>—</u>	<u>1,878,733</u>
Total capitalization. . . . .	3,795,791	179,538	129,289	36,919	(342,347)	3,799,190
Current liabilities						
Current maturities of long- term debt . . . . .	301,250	—	—	1,959	—	303,209
Short-term debt . . . . .	154,471	—	—	—	—	154,471
Liabilities from risk management activities . . . . .	33,556	34,399	111	—	(33,236)	34,830
Other current liabilities . . . . .	747,305	343,128	85,101	—	(40,526)	1,135,008
Intercompany payables. . . . .	—	101,630	502,232	—	(603,862)	—
Total current liabilities . . . . .	<u>1,236,582</u>	<u>479,157</u>	<u>587,444</u>	<u>1,959</u>	<u>(677,624)</u>	<u>1,627,518</u>
Deferred income taxes . . . . .	307,800	(22,878)	37,173	2,201	—	324,296
Noncurrent liabilities from risk management activities . . . . .	—	278	1	—	(2)	277
Regulatory cost of removal obligation . . . . .	255,321	—	—	—	—	255,321
Deferred credits and other liabilities . . . . .	<u>200,634</u>	<u>540</u>	<u>3,923</u>	<u>4,696</u>	<u>—</u>	<u>209,793</u>
	<u><u>\$5,796,128</u></u>	<u><u>\$636,635</u></u>	<u><u>\$757,830</u></u>	<u><u>\$45,775</u></u>	<u><u>\$(1,019,973)</u></u>	<u><u>\$6,216,395</u></u>

**ATMOS ENERGY CORPORATION**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

	September 30, 2006					
	<u>Utility</u>	<u>Natural Gas Marketing</u>	<u>Pipeline and Storage</u>	<u>Other Nonutility</u>	<u>Eliminations</u>	<u>Consolidated</u>
	(In thousands)					
<b>ASSETS</b>						
Property, plant and equipment, net . .	\$3,083,301	\$ 7,531	\$537,028	\$ 1,296	\$ —	\$3,629,156
Investment in subsidiaries . . . . .	281,143	(2,155)	—	—	(278,988)	—
Current assets						
Cash and cash equivalents . . . . .	8,738	45,481	—	21,596	—	75,815
Cash held on deposit in margin account . . . . .	—	35,647	—	—	—	35,647
Assets from risk management activities . . . . .	—	13,164	19,040	—	(19,651)	12,553
Other current assets . . . . .	714,472	261,435	26,325	8,119	(16,821)	993,530
Intercompany receivables . . . . .	<u>602,809</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>(602,809)</u>	<u>—</u>
Total current assets . . . . .	1,326,019	355,727	45,365	29,715	(639,281)	1,117,545
Intangible assets . . . . .	—	3,152	—	—	—	3,152
Goodwill . . . . .	567,221	24,282	143,866	—	—	735,369
Noncurrent assets from risk management activities . . . . .	—	6,190	5	—	(9)	6,186
Deferred charges and other assets . .	<u>204,617</u>	<u>1,315</u>	<u>5,301</u>	<u>16,906</u>	<u>—</u>	<u>228,139</u>
	<u>\$5,462,301</u>	<u>\$396,042</u>	<u>\$731,565</u>	<u>\$47,917</u>	<u>\$(918,278)</u>	<u>\$5,719,547</u>
<b>CAPITALIZATION AND LIABILITIES</b>						
Shareholders' equity . . . . .	\$1,648,098	\$139,863	\$107,640	\$33,640	\$(281,143)	\$1,648,098
Long-term debt . . . . .	<u>2,176,473</u>	<u>—</u>	<u>—</u>	<u>3,889</u>	<u>—</u>	<u>2,180,362</u>
Total capitalization . . . . .	3,824,571	139,863	107,640	37,529	(281,143)	3,828,460
Current liabilities						
Current maturities of long-term debt . . . . .	1,250	—	—	1,936	—	3,186
Short-term debt . . . . .	382,416	—	—	—	—	382,416
Liabilities from risk management activities . . . . .	27,209	22,500	531	—	(19,571)	30,669
Other current liabilities . . . . .	473,101	183,077	61,458	—	(14,746)	702,890
Intercompany payables . . . . .	<u>—</u>	<u>75,665</u>	<u>525,895</u>	<u>1,249</u>	<u>(602,809)</u>	<u>—</u>
Total current liabilities . . . . .	883,976	281,242	587,884	3,185	(637,126)	1,119,161
Deferred income taxes . . . . .	297,821	(25,777)	31,927	2,201	—	306,172
Noncurrent liabilities from risk management activities . . . . .	—	280	5	—	(9)	276
Regulatory cost of removal obligation . . . . .	261,376	—	—	—	—	261,376
Deferred credits and other liabilities . . . . .	<u>194,557</u>	<u>434</u>	<u>4,109</u>	<u>5,002</u>	<u>—</u>	<u>204,102</u>
	<u>\$5,462,301</u>	<u>\$396,042</u>	<u>\$731,565</u>	<u>\$47,917</u>	<u>\$(918,278)</u>	<u>\$5,719,547</u>

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors  
Atmos Energy Corporation

We have reviewed the condensed consolidated balance sheet of Atmos Energy Corporation as of December 31, 2006, and the related condensed consolidated statements of income for the three-month periods ended December 31, 2006 and 2005, and the condensed consolidated statements of cash flows for the three-month periods ended December 31, 2006 and 2005. These financial statements are the responsibility of the Company's management.

We conducted our review in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the condensed consolidated financial statements referred to above for them to be in conformity with U.S. generally accepted accounting principles.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Atmos Energy Corporation as of September 30, 2006, and the related consolidated statements of income, shareholders' equity, and cash flows for the year then ended, not presented herein, and in our report dated November 20, 2006, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of September 30, 2006, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

ERNST & YOUNG LLP

Dallas, Texas  
February 5, 2007

## **Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations**

### **INTRODUCTION**

The following discussion should be read in conjunction with the condensed consolidated financial statements in this Quarterly Report on Form 10-Q and Management's Discussion and Analysis in our Annual Report on Form 10-K for the year ended September 30, 2006.

#### ***Cautionary Statement for the Purposes of the Safe Harbor under the Private Securities Litigation Reform Act of 1995***

The statements contained in this Quarterly Report on Form 10-Q may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this Report are forward-looking statements made in good faith by us and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this Report, or any other of our documents or oral presentations, the words "anticipate", "believe", "estimate", "expect", "forecast", "goal", "intend", "objective", "plan", "projection", "seek", "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the statements relating to our strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties include the following: regulatory trends and decisions, including deregulation initiatives and the impact of rate proceedings before various state regulatory commissions; adverse weather conditions, such as warmer than normal weather in our utility service territories or colder than normal weather that could adversely affect our natural gas marketing activities; the concentration of our distribution, pipeline and storage operations in one state; impact of environmental regulations on our business; market risks beyond our control affecting our risk management activities including market liquidity, commodity price volatility, increasing interest rates and counterparty creditworthiness; our ability to continue to access the capital markets; the effects of inflation and changes in the availability and prices of natural gas, including the volatility of natural gas prices; increased competition from energy suppliers and alternative forms of energy; increased costs of providing pension and postretirement health care benefits; the capital-intensive nature of our distribution business; the inherent hazards and risks involved in operating our distribution business; and other uncertainties, which may be discussed herein, all of which are difficult to predict and many of which are beyond our control. A more detailed discussion of these risks and uncertainties may be found in our Form 10-K for the year ended September 30, 2006. Accordingly, while we believe these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. Further, we undertake no obligation to update or revise any of our forward-looking statements whether as a result of new information, future events or otherwise.

### **OVERVIEW**

Atmos Energy Corporation and our subsidiaries are engaged primarily in the natural gas utility business as well as certain nonutility businesses. We distribute natural gas through sales and transportation arrangements to approximately 3.2 million residential, commercial, public authority and industrial customers throughout our six regulated utility divisions, which cover service areas located in 12 states. In addition, we transport natural gas for others through our distribution system.

Through our nonutility businesses, we primarily provide natural gas management and marketing services to municipalities, other local gas distribution companies and industrial customers in 22 states and natural gas transportation and storage services to certain of our utility operations and to third parties.

Our operations are divided into four segments:

- the utility segment, which includes our regulated natural gas distribution and related sales operations,
- the natural gas marketing segment, which includes a variety of nonregulated natural gas management services,

- the pipeline and storage segment, which includes our regulated and nonregulated natural gas transmission and storage services and
- the other nonutility segment, which includes all of our other nonregulated nonutility operations.

The following summarizes the results of our operations and other significant events for the three months ended December 31, 2006:

- Our utility segment net income decreased by \$16.6 million during the three months ended December 31, 2006 compared with the three months ended December 31, 2005. The decrease reflects lower gross profit margin primarily associated with lower revenue-related taxes coupled with higher operating expenses.
- Our natural gas marketing segment net income increased \$23.5 million during the three months ended December 31, 2006 compared with the three months ended December 31, 2005. The increase in natural gas marketing net income primarily reflects favorable movements in AEM's unrealized margin, partially offset by lower realized margins.
- Our pipeline and storage segment net income increased \$3.4 million during the three months ended December 31, 2006 compared with the three months ended December 31, 2005. Increased net income primarily reflects incremental gross profit margins from our North Side Loop and other pipeline compression projects completed in fiscal 2006 and increased margins from the Gas Reliability Infrastructure Program (GRIP).
- In December 2006, we filed a new \$900 million shelf registration statement that replaced our previously existing shelf registration statement. Upon completion of the filing of this new registration statement, we issued approximately 6.3 million shares of common stock, which generated approximately \$192 million of net proceeds which we used to repay a portion of our short-term debt.
- Our total-debt-to-capitalization ratio at December 31, 2006 was 54.9 percent compared with 60.9 percent at September 30, 2006 primarily reflecting the favorable impact of our equity offering in December 2006.
- For the three months ended December 31, 2006, we generated \$165.0 million in operating cash flow compared with \$195.4 million used in operations for the three months ended December 31, 2005, primarily reflecting the favorable impact of lower natural gas prices on our working capital.
- Capital expenditures decreased to \$87.0 million during the three months ended December 31, 2006 from \$102.5 million in the prior-year period. The decrease primarily reflects the absence of capital spending for the North Side Loop and other compression projects, which were completed in fiscal 2006.

## **CRITICAL ACCOUNTING ESTIMATES AND POLICIES**

Our condensed consolidated financial statements were prepared in accordance with accounting principles generally accepted in the United States. Preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We based our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. On an ongoing basis, we evaluate our estimates, including those related to risk management and trading activities, allowance for doubtful accounts, legal and environmental accruals, insurance accruals, pension and postretirement obligations, deferred income taxes and the valuation of goodwill, indefinite-lived intangible assets and other long-lived assets. Actual results may differ from such estimates.

Our critical accounting policies used in the preparation of our consolidated financial statements are described in our Annual Report on Form 10-K for the year ended September 30, 2006 and include the following:

- Regulation
- Revenue Recognition
- Allowance for Doubtful Accounts

- Derivatives and Hedging Activities
- Impairment Assessments
- Pension and Other Postretirement Plans

Our critical accounting policies are reviewed by the Audit Committee on a quarterly basis. There have been no significant changes to these critical accounting policies during the three months ended December 31, 2006.

## RESULTS OF OPERATIONS

The following table presents our financial highlights for the three-month periods ended December 31, 2006 and 2005:

	Three Months Ended December 31	
	2006	2005
	(In thousands, unless otherwise noted)	
Operating revenues . . . . .	\$1,602,633	\$2,283,820
Gross profit . . . . .	375,592	346,590
Operating expenses . . . . .	204,432	196,893
Operating income . . . . .	171,160	149,697
Miscellaneous income . . . . .	1,579	448
Interest charges . . . . .	39,532	36,189
Income before income taxes . . . . .	133,207	113,956
Income tax expense . . . . .	51,946	42,929
Net income . . . . .	\$ 81,261	\$ 71,027
Utility sales volumes — MMcf . . . . .	86,400	95,188
Utility transportation volumes — MMcf . . . . .	<u>32,694</u>	<u>30,602</u>
Total utility throughput — MMcf . . . . .	<u>119,094</u>	<u>125,790</u>
Natural gas marketing sales volumes — MMcf . . . . .	<u>77,526</u>	<u>71,496</u>
Pipeline transportation volumes — MMcf . . . . .	<u>118,955</u>	<u>91,595</u>
Heating degree days <sup>(1)</sup>		
Actual (weighted average) . . . . .	1,135	1,056
Percent of normal . . . . .	101%	93%
Consolidated utility average transportation revenue per Mcf . . . . .	\$ 0.48	\$ 0.51
Consolidated utility average cost of gas per Mcf sold . . . . .	\$ 8.12	\$ 11.82

<sup>(1)</sup> Adjusted for service areas that have weather-normalized operations. For service areas that have weather normalized operations, normal degree days are used instead of actual degree days in computing the total number of heating degree days.

The following table shows our operating income by segment for the three-month periods ended December 31, 2006 and 2005. The presentation of our utility operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	<b>Three Months Ended December 31</b>			
	<b>2006</b>		<b>2005</b>	
	<b>Operating Income</b>	<b>Heating Degree Days Percent of Normal<sup>(1)</sup></b>	<b>Operating Income</b>	<b>Heating Degree Days Percent of Normal<sup>(1)</sup></b>
(In thousands, except degree day information)				
Colorado-Kansas . . . . .	\$ 8,672	103%	\$ 8,610	99%
Kentucky/Mid-States <sup>(2)</sup> . . . . .	14,203	101%	20,490	99%
Louisiana . . . . .	10,593	107%	7,891	95%
Mid-Tex . . . . .	35,340	100%	50,787	83%
Mississippi . . . . .	7,599	103%	9,993	103%
West Texas . . . . .	6,506	100%	6,131	100%
Other . . . . .	<u>198</u>	—	<u>2,347</u>	—
Utility segment . . . . .	83,111	101%	106,249	93%
Natural gas marketing segment . . . . .	56,978	—	21,254	—
Pipeline and storage segment . . . . .	30,966	—	22,052	—
Other nonutility segment and other . . . . .	<u>105</u>	—	<u>142</u>	—
Consolidated operating income . . . . .	<u>\$171,160</u>	101%	<u>\$149,697</u>	93%

<sup>(1)</sup> Adjusted for service areas that have weather-normalized operations.

<sup>(2)</sup> Effective October 1, 2006, the Kentucky and Mid-States Divisions were combined. Prior year amounts have been restated to conform to this new presentation.

***Three Months Ended December 31, 2006 compared with Three Months Ended December 31, 2005***

***Utility segment***

Our utility segment has historically contributed 65 to 85 percent of our consolidated net income. However, in recent years, this contribution has slightly declined as our nonutility businesses have grown and our utility operations have experienced the adverse effects of warmer than normal weather.

Natural gas sales to residential, commercial and public authority customers are affected by winter heating season requirements, whereas natural gas sales to industrial customers are much less weather sensitive. As residential, commercial and public authority customers comprise approximately 90 percent of our gas sales volumes, the results of operations for our utility segment are seasonal. We typically experience higher operating revenues and net income during the period from October through March of each year and lower operating revenues and either lower net income or net losses during the period from April through September of each year. Accordingly, our second fiscal quarter has historically been our most critical earnings quarter with an average of approximately 64 percent of our consolidated net income having been earned in the second quarter during the three most recently completed fiscal years. Additionally, we typically experience higher levels of accounts receivable, accounts payable, gas stored underground and short-term debt balances during the winter heating season due to the seasonal nature of our revenues and the need to purchase and store gas to support these operations.

The primary factors that currently impact the results of our utility operations are regulatory decisions and trends, the increased use of energy-efficient appliances by our customers, competitive factors in the energy industry and economic conditions in our service areas.

Seasonal weather patterns can also affect our utility operations. However, the effect of weather that is above or below normal is substantially offset through weather normalization adjustments, known as WNA, which, beginning

with the 2006-2007 winter heating season, are approved by regulators for over 90 percent of our residential and commercial meters in the following states for the following time periods:

Georgia . . . . .	October – May
Kansas . . . . .	October – May
Kentucky . . . . .	November – April
Louisiana <sup>(1)</sup> . . . . .	December – March
Mississippi . . . . .	November – April
Tennessee . . . . .	November – April
Texas <sup>(1)</sup> . . . . .	October – May
Virginia . . . . .	January – December

<sup>(1)</sup> Effective beginning for the 2006-2007 winter heating season in our Mid-Tex and Louisiana divisions.

WNA allows us to increase customers' bills to offset lower gas usage when weather is warmer than normal and decrease customers' bills to offset higher gas usage when weather is colder than normal. Although our WNA periods do not cover the entire heating season in all jurisdictions, we believe these mechanisms substantially insulate our utility gross profit margin from the effects of weather.

Our utility operations are also affected by the cost of natural gas. The cost of gas is passed through to our customers without markup. Therefore, increases in the cost of gas are offset by a corresponding increase in revenues. Accordingly, we believe gross profit margin is a better indicator of our financial performance than revenues. However, gross profit margins in our Texas and Mississippi service areas include franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). We record the tax expense as a component of taxes, other than income. Although changes in revenue-related taxes arising from changes in gas cost affect gross profit, over time the impact is usually offset within operating income. Timing differences do exist between the recognition of revenue for franchise fees collected from our customers and the recognition of expense of franchise taxes. The effect of these timing differences can be significant in periods of volatile gas prices, particularly in our Mid-Tex Division. These timing differences may favorably or unfavorably affect net income; however, they offset over time with no permanent impact on net income.

Higher gas costs affect our utility operations in other ways as well. Higher gas costs may cause customers to conserve, or, in the case of industrial customers, to use alternative energy sources. Higher gas costs may also adversely impact our accounts receivable collections, resulting in higher bad debt expense and may require us to increase borrowings under our credit facilities resulting in higher interest expense.

Operating income

Utility gross profit margin decreased \$17.6 million to \$262.6 million for the three months ended December 31, 2006 from \$280.2 million for the three months ended December 31, 2005. Total throughput for our utility business was 119.1 billion cubic feet (Bcf) during the current-year period compared to 125.8 Bcf in the prior-year period.

The decrease in utility gross profit margin primarily reflects a reduction in revenue-related taxes. Due to a significant decline in the cost of gas in the current-year quarter compared with the prior-year quarter, revenue-related taxes included in gross profit margin decreased approximately \$15.2 million; however, franchise and state gross receipts tax expense recorded as a component of taxes, other than income only decreased \$2.7 million, which resulted in a \$12.5 million reduction in operating income when compared with the prior-year quarter.

Gross profit was also adversely affected by a reduction arising from the Tennessee Regulatory Authority's (TRA) decision in October 2006 to reduce our annual rates in Tennessee by \$6.1 million, which adversely impacted gross profit margin by \$2.0 million during the quarter.

These decreases were partially offset by a \$7.5 million increase associated with the implementation of WNA in our Mid-Tex and Louisiana divisions beginning with the 2006-2007 winter heating season coupled with \$8.7 million of rate increases received from our fiscal 2004 and 2005 GRIP filings, which became effective in February 2006, and our 2005 Rate Stabilization Clause (RSC) filing in our LGS service area in Louisiana, which became effective

in September 2006. As discussed under *Recent Ratemaking Developments*, amounts billed under this RSC were subject to refund until December 2006 when the Louisiana Public Service Commission (LPSC) completed its review of our filing. The final decision from the LPSC did not materially affect the amounts billed subject to refund.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, increased to \$179.5 million for the three months ended December 31, 2006 from \$173.9 million for the three months ended December 31, 2005.

Operation and maintenance expense, excluding the provision for doubtful accounts, increased \$7.3 million primarily due to increased employee costs and other administrative costs and increased costs arising from increased line locate activity in our Mid-Tex Division. Partially offsetting these increases was the absence of \$2.0 million of Hurricane Katrina-related costs recorded in the prior-year quarter.

The provision for doubtful accounts decreased \$2.0 million to \$6.4 million for the three months ended December 31, 2006. The decrease primarily was attributable to lower revenues arising from lower gas costs during the current quarter compared with the prior-year quarter. In the utility segment, the average cost of natural gas for the three months ended December 31, 2006 was \$8.12 per thousand cubic feet (Mcf), compared with \$11.82 per Mcf for the three months ended December 31, 2005.

Depreciation and amortization expense increased \$5.4 million in the first quarter of fiscal 2007 compared with the first quarter of fiscal 2006. This increase was primarily due to the absence in the current-year quarter of a \$2.8 million reduction in depreciation expense recorded in the prior-year quarter arising from the Mississippi Public Service Commission's decision to allow certain deferred costs in our rate base. Increases in assets placed in service during fiscal 2006 also contributed to the increase in depreciation and amortization expense in the current-year quarter.

As a result of the aforementioned factors, our utility segment operating income for the three months ended December 31, 2006 decreased to \$83.1 million from \$106.2 million for the three months ended December 31, 2005.

#### Interest charges

Interest charges allocated to the utility segment for the three months ended December 31, 2006 increased to \$32.5 million from \$31.6 million for the three months ended December 31, 2005. The increase was primarily attributable to higher average outstanding short-term debt balances in the current-year period compared with the prior-year period coupled with an approximate 120 basis point increase in the interest rate on our \$300 million unsecured floating rate Senior Notes due October 2007 due to an increase in the three-month LIBOR rate. With the completion of our equity offering in December 2006, we anticipate lower outstanding short-term debt balances, which should reduce interest expense for the remainder of the fiscal year.

#### *Natural gas marketing segment*

Our natural gas marketing segment aggregates and purchases gas supply, arranges transportation and/or storage logistics and ultimately delivers gas to our customers at competitive prices. To facilitate this process, we utilize proprietary and customer-owned transportation and storage assets to provide the various services our customers request, including furnishing natural gas supplies at fixed and market-based prices, contract negotiation and administration, load forecasting, gas storage acquisition and management services, transportation services, peaking sales and balancing services, capacity utilization strategies and gas price hedging through the use of derivative products. As a result, our revenues arise from the types of commercial transactions we have structured with our customers and include the value we extract by optimizing the storage and transportation capacity we own or control as well as revenues for services we deliver.

To optimize the storage and transportation capacity we own or control, we participate in transactions in which we combine the natural gas commodity and transportation costs to minimize our costs incurred to serve our customers by identifying the lowest cost alternative within the natural gas supplies, transportation and markets to which we have access. Additionally, we engage in natural gas storage transactions in which we seek to find and profit from the pricing differences that occur over time. We purchase physical natural gas and then sell financial contracts at advantageous prices to lock in a gross profit margin. Through the use of transportation and storage

services and derivative contracts, we are able to capture gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time.

Operating income

Gross profit margin for our natural gas marketing segment consists primarily of marketing activities, which represent the utilization of proprietary and customer-owned transportation and storage assets to provide various services our customers request and storage activities, which are comprised of the optimization of our managed proprietary and third-party storage and transportation assets.

Our natural gas marketing segment's gross profit margin for the three months ended December 31, 2006 and 2005 is summarized as follows:

	<b>Three Months Ended December 31</b>	
	<u>2006</u>	<u>2005</u>
	<b>(In thousands, except physical position)</b>	
Storage Activities		
Realized margin . . . . .	\$ (5,790)	\$ 26,272
Unrealized margin . . . . .	<u>48,891</u>	<u>(23,792)</u>
Total Storage Activities . . . . .	43,101	2,480
Marketing Activities		
Realized margin . . . . .	20,069	29,567
Unrealized margin . . . . .	<u>(36)</u>	<u>(5,728)</u>
Total Marketing Activities . . . . .	<u>20,033</u>	<u>23,839</u>
Gross profit . . . . .	<u>\$63,134</u>	<u>\$ 26,319</u>
Net physical position (Bcf) . . . . .	<u>21.0</u>	<u>12.8</u>

Our natural gas marketing segment's gross profit margin was \$63.1 million for the three months ended December 31, 2006 compared to gross profit of \$26.3 million for the three months ended December 31, 2005. Gross profit margin for the three months ended December 31, 2006 included an unrealized gain of \$48.9 million compared with an unrealized loss of \$29.5 million in the prior-year period. Natural gas marketing sales volumes were 88.0 Bcf during the three months ended December 31, 2006 compared with 87.8 Bcf for the prior-year period. Excluding intersegment sales volumes, natural gas marketing sales volumes were 77.5 Bcf during the current-year period compared with 71.5 Bcf in the prior-year period. The increase in consolidated natural gas marketing sales volumes primarily was attributable to successfully executed marketing strategies.

Our storage activities generated gross profit of \$43.1 million for the three months ended December 31, 2006 compared to gross profit of \$2.5 million for the three months ended December 31, 2005. The \$40.6 million increase in our storage activities was primarily due to favorable movements during the three months ended December 31, 2006 in the forward natural gas prices used to value the financial hedges designated against our physical inventory as well as favorable movements in market (spot) prices used to value our physical storage. This mark-to-market impact was magnified by an 8.2 Bcf increase in our net physical position at December 31, 2006 compared to the prior-year quarter. Differences between the forward and spot prices may continue to cause material volatility in our unrealized margin. However, the economic gross profit we have captured in the original transactions will remain essentially unchanged.

Realized margins from storage activities decreased during the three months ended December 31, 2006 compared with the three months ended December 31, 2005. This decrease was primarily attributable to our ability to successfully capture more favorable arbitrage spreads arising from increased market volatility in the prior-year quarter coupled with the strategic decision to roll storage withdrawal schedules to forward months to obtain improved future arbitrage spreads and buy flowing gas at lower prices to meet current contractual delivery requirements during the three months ended December 31, 2006.

Our marketing activities generated \$20.0 million for the three months ended December 31, 2006 compared with \$23.8 million for the three months ended December 31, 2005. The \$3.8 million decrease in our marketing activities reflects lower realized margins partially offset by increased unrealized margins. The decrease in realized margins is primarily attributable to realizing lower margins in a less volatile market during the quarter compared with the prior-year quarter, partially offset by increased sales volumes attributable to successfully executing marketing strategies. The favorable unrealized margin variance was primarily due to favorable movement during the three months ended December 31, 2006 in the forward natural gas prices associated with financial derivatives used in these activities.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes other than income taxes, increased to \$6.2 million for the three months ended December 31, 2006 from \$5.1 million for the three months ended December 31, 2005. The increase in operating expense primarily was attributable to an increase in employee and other administrative costs.

The increase in gross profit margin, partially offset by higher operating expenses, resulted in an increase in our natural gas marketing segment operating income to \$57.0 million for the three months ended December 31, 2006 compared with operating income of \$21.3 million for the three months ended December 31, 2005.

#### Interest charges

Interest charges allocated to the natural gas marketing segment for the three months ended December 31, 2006 decreased to \$1.0 million from \$2.9 million for the three months ended December 31, 2005. The decrease was attributable to the use of updated allocation factors for fiscal 2007. These factors are reviewed and updated on an annual basis.

#### ***Pipeline and storage segment***

Our pipeline and storage segment consists of the regulated pipeline and storage operations of the Atmos Pipeline — Texas Division and the nonregulated pipeline and storage operations of Atmos Pipeline and Storage, LLC (APS). The Atmos Pipeline — Texas Division transports natural gas to our Mid-Tex Division and for third parties and manages five underground storage reservoirs in Texas. We also provide ancillary services customary in the pipeline industry including parking arrangements, lending and sales of inventory on hand. These operations represent one of the largest intrastate pipeline operations in Texas with a heavy concentration in the established natural gas-producing areas of central, northern and eastern Texas, extending into or near the major producing areas of the Texas Gulf Coast and the Delaware and Val Verde Basins of West Texas. This pipeline system provides access to nine basins located in Texas, which are estimated to contain a substantial portion of the nation's remaining onshore natural gas reserves. APS owns or has an interest in underground storage fields in Kentucky and Louisiana. We also use these storage facilities to reduce the need to contract for additional pipeline capacity to meet customer demand during peak periods.

Similar to our utility segment, our pipeline and storage segment is impacted by seasonal weather patterns, competitive factors in the energy industry and economic conditions in our service areas. Natural gas transportation requirements are affected by the winter heating season requirements of our customers. This generally results in higher operating revenues and net income during the period from October through March of each year and lower operating revenues and either lower net income or net losses during the period from April through September of each year. Further, as the Atmos Pipeline — Texas Division operations provide all of the natural gas for our Mid-Tex Division, the results of this segment are highly dependent upon the natural gas requirements of this division. As a regulated pipeline, the operations of the Atmos Pipeline — Texas Division may be impacted by the timing of when costs and expenses are incurred and when these costs and expenses are recovered through its tariffs.

#### Operating income

Gross profit margin for our pipeline and storage segment primarily consists of transportation margins earned from our Mid-Tex Division and from third parties, other ancillary pipeline services and asset management fees

earned by APS. Our pipeline and storage segment's gross profit margin was comprised of the following components for the three months ended December 31, 2006 and 2005:

	<b>Three Months Ended December 31</b>	
	<b>2006</b>	<b>2005</b>
	<b>(In thousands)</b>	
Mid-Tex transportation . . . . .	\$20,464	\$19,791
Third-party transportation . . . . .	16,148	13,699
Asset management fees . . . . .	1,217	(987)
Storage and park and lend services . . . . .	3,991	2,514
Unrealized gains . . . . .	6,220	3,394
Other . . . . .	<u>1,587</u>	<u>1,301</u>
Gross profit . . . . .	<u>\$49,627</u>	<u>\$39,712</u>

Pipeline and storage gross profit increased to \$49.6 million for the three months ended December 31, 2006 from \$39.7 million for the three months ended December 31, 2005. Total pipeline transportation volumes were 172.8 Bcf during the three months ended December 31, 2006 compared with 147.0 Bcf for the prior year. Excluding intersegment transportation volumes, total pipeline transportation volumes were 119.0 Bcf during the current-year period compared with 91.6 Bcf in the prior-year period.

The increase in gross profit and throughput was primarily attributable to incremental margins and throughput generated from our North Side Loop and other compression projects of \$4.3 million coupled with a \$1.1 million increase received from our 2005 GRIP filing. Additionally, storage and parking and lending services on Atmos Pipeline — Texas increased compared with the prior-year quarter as a result of the widening of pricing differentials between the pipeline's hubs, which increased the attractiveness of storing gas on the pipeline and our ability to obtain improved margins for these services.

Increases in APS' margins due to its ability to capture more favorable arbitrage spreads on its asset management contracts also contributed to this segment's improved gross profit margin. These margins reflect an unrealized component of this segment's margin as APS hedges its risk associated with these contracts and the associated gain or loss is not recognized until the underlying transaction and derivative contracts are settled. During the first quarter of fiscal 2007, favorable movements in the forward natural gas prices used to value the financial hedges designated against the physical inventory underlying these contracts resulted in an increased unrealized gain compared with the prior-year period.

Operating expenses increased to \$18.7 million for the three months ended December 31, 2006 from \$17.7 million for the three months ended December 31, 2005 due to higher administrative and other operating costs primarily associated with the North Side Loop and other compression projects that were completed in fiscal 2006.

As a result of the aforementioned factors, our pipeline and storage segment operating income for the three months ended December 31, 2006 increased to \$31.0 million from \$22.1 million for the three months ended December 31, 2005.

Interest charges

Interest charges allocated to the pipeline and storage segment for the three months ended December 31, 2006 increased to \$8.4 million from \$6.0 million for the three months ended December 31, 2005. The increase was attributable to the use of updated allocation factors for fiscal 2007. These factors are reviewed and updated on an annual basis.

***Other nonutility segment***

Our other nonutility businesses consist primarily of the operations of Atmos Energy Services, LLC (AES), and Atmos Power Systems, Inc. Through AES, we provide natural gas management services to our utility operations,

other than the Mid-Tex Division. These services include aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering the gas to our utility service areas at competitive prices. The revenues of AES represent charges to our utility divisions equal to the costs incurred to provide those services. Effective January 1, 2007, our shared services division began providing these services to our utility operations, which were formerly provided by AES. Through Atmos Power Systems, Inc., we have constructed electric peaking power-generating plants and associated facilities and have entered into agreements to lease these plants.

Operating income for this segment primarily reflects the leasing income associated with two sales-type lease transactions completed in 2001 and 2002 and was essentially unchanged for the three months ended December 31, 2006 compared with the prior-year quarter.

### Liquidity and Capital Resources

Our working capital and liquidity for capital expenditures and other cash needs are provided from internally generated funds, borrowings under our credit facilities and commercial paper program. Additionally, from time to time, we raise funds from the public debt and equity capital markets to fund our liquidity needs.

In October 2007, our \$300 million unsecured floating rate Senior Notes will mature. We are currently evaluating alternatives to refinance this debt, and we believe these refinancing efforts will be successful. We believe these funds, combined with the other sources of funds described above will provide the necessary working capital and liquidity for capital expenditures and other cash needs for the remainder of fiscal 2007.

### Capitalization

The following table presents our capitalization as of December 31, 2006 and September 30, 2006:

	<u>December 31, 2006</u>		<u>September 30, 2006</u>	
	(In thousands, except percentages)			
Short-term debt . . . . .	\$ 154,471	3.6%	\$ 382,416	9.1%
Long-term debt . . . . .	2,181,942	51.3%	2,183,548	51.8%
Shareholders' equity . . . . .	<u>1,920,457</u>	<u>45.1%</u>	<u>1,648,098</u>	<u>39.1%</u>
Total capitalization, including short-term debt . . . . .	<u>\$4,256,870</u>	<u>100.0%</u>	<u>\$4,214,062</u>	<u>100.0%</u>

Total debt as a percentage of total capitalization, including short-term debt, was 54.9 percent at December 31, 2006, and 60.9 percent at September 30, 2006. The decrease in the debt to capitalization ratio was primarily attributable to the application of the net proceeds provided from our equity offering in December 2006 to repay a portion of our short-term debt. Our ratio of total debt to capitalization is typically greater during the winter heating season as we make additional short-term borrowings to fund natural gas purchases and meet our working capital requirements. We intend to maintain our capitalization ratio in a target range of 50 to 55 percent through cash flow generated from operations, continued issuance of new common stock under our Direct Stock Purchase Plan and Retirement Savings Plan, access to the equity capital markets and reduced annual maintenance and capital expenditures.

### Cash Flows

Our internally generated funds may change in the future due to a number of factors, some of which we cannot control. These include regulatory changes, prices for our products and services, demand for such products and services, margin requirements resulting from significant changes in commodity prices, operational risks and other factors.

#### *Cash flows from operating activities*

Period-over-period changes in our operating cash flows primarily are attributable to changes in net income, working capital changes, particularly within our utility segment resulting from the price of natural gas and the timing of customer collections, payments for natural gas purchases and deferred gas cost recoveries.

For the three months ended December 31, 2006, we generated operating cash flow of \$165.0 million from operating activities compared with a cash outflow of \$195.4 million for the three months ended December 31, 2005. Quarter over quarter, our operating cash flow was favorably impacted by lower natural gas prices compared with the prior-year quarter, which reduced the levels of accounts receivable, gas stored underground, undercollected deferred gas costs and accounts payable recorded on our balance sheet as of December 31, 2006. Specifically, changes in accounts receivable and gas stored underground balances increased operating cash flow by \$457.2 million. Additionally, improved management of our deferred gas cost balances increased operating cash flow by \$86.5 million. Decreases in cash required to collateralize our risk management accounts also increased operating cash flow by \$28.8 million. These increases were partially offset by \$225.9 million associated with unfavorable timing of payments for accounts payable and other accrued liabilities. Favorable changes in other working capital and other changes totaled \$13.8 million and were primarily attributable to increased net income.

#### *Cash flows from investing activities*

During the last three years, a substantial portion of our cash resources has been used to fund acquisitions, new pipeline expansion projects and our ongoing utility construction program. Our ongoing utility construction program enables us to provide natural gas distribution services to our existing customer base, to expand our natural gas distribution services into new markets, to enhance the integrity of our pipelines and, more recently, to expand our intrastate pipeline network. In executing our current rate strategy, we are directing discretionary capital spending to jurisdictions that permit us to earn a timely return in excess of our cost of capital. Currently, our Mid-Tex, Louisiana, Mississippi and West Texas utility divisions and our Atmos Pipeline — Texas Division have rate designs that provide the opportunity to include in their rate base approved capital costs on a periodic basis without having to file a rate case.

Capital expenditures for fiscal 2007 are expected to range from \$425 million to \$440 million. For the three months ended December 31, 2006, we incurred \$87.0 million for capital expenditures compared with \$102.5 million for the three months ended December 31, 2005. The decrease in capital spending primarily reflects the absence of capital expenditures associated with our North Side Loop and other pipeline compression projects, which were completed in the third quarter of fiscal 2006.

#### *Cash flows from financing activities*

For the three months ended December 31, 2006, our financing activities reflected a use of cash of \$58.1 million compared with the \$308.3 million provided from financing activities in the prior-year period. Our significant financing activities for the three months ended December 31, 2006 and 2005 are summarized as follows.

- In December 2006, we sold 6.3 million shares of common stock, including the underwriters' exercise of their overallotment option of 0.8 million shares, under a new shelf registration statement filed in December 2006, generating net proceeds of approximately \$192 million. The net proceeds from this issuance were used to reduce our short-term debt.
- In addition to this equity offering, during the three months ended December 31, 2006, we issued 0.2 million shares of common stock under our various plans which generated net proceeds of \$5.6 million. In addition, we granted 0.2 million shares of common stock under our Long-Term Incentive Plan.
- During the three months ended December 31, 2006, we decreased our borrowings under our credit facilities by \$227.9 million. The decrease reflects the application of the net proceeds received from the equity offering to reduce short-term indebtedness. Additionally, the reduction in natural gas prices improved our operating cash flow and reduced our need to fund natural gas purchases and other working capital needs from short-term borrowings.
- During the three months ended December 31, 2006, we paid \$26.3 million in cash dividends compared with \$25.4 million for the three months ended December 31, 2005. The increase in dividends paid over the prior-year period reflects the increase in our dividend rate from \$0.315 per share during the three months ended December 31, 2005 to \$0.32 per share during the three months ended December 31, 2006 combined with new share issuances under our various plans.

The following table summarizes our share issuances for the three months ended December 31, 2006 and 2005.

	<b>Three Months Ended December 31</b>	
	<u>2006</u>	<u>2005</u>
Shares issued:		
Retirement Savings Plan . . . . .	85,162	105,875
Direct Stock Purchase Plan . . . . .	80,701	103,202
Outside Directors Stock-for-Fee Plan . . . . .	669	667
Long-Term Incentive Plan . . . . .	273,799	103,753
Public Offering . . . . .	<u>6,325,000</u>	<u>—</u>
Total shares issued . . . . .	<u>6,765,331</u>	<u>313,497</u>

### **Shelf Registration**

On December 4, 2006, we filed a registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to \$900 million in new common stock and/or debt securities available for issuance, including approximately \$401.5 million of capacity carried over from our prior shelf registration statement filed with the SEC in August 2004. In December 2006, we sold 6.3 million shares of common stock and used the net proceeds to reduce short-term debt. After this issuance, we have approximately \$701 million of availability remaining under the registration statement.

### **Credit Facilities**

We maintain both committed and uncommitted credit facilities. Borrowings under our uncommitted credit facilities are made on a when-and-as-needed basis at the discretion of the banks. Our credit capacity and the amount of unused borrowing capacity are affected by the seasonal nature of the natural gas business and our short-term borrowing requirements, which are typically highest during colder winter months. Our working capital needs can vary significantly due to changes in the price of natural gas charged by suppliers and the increased gas supplies required to meet customers' needs during periods of cold weather. Our cash needs for working capital have increased substantially in recent years as a result of the significant increase in the price of natural gas.

In December 2006, we replaced our \$600 million three-year revolving credit facility with a new \$600 million five-year revolving credit facility. In addition, in November 2006, we entered into a new \$300 million 364-day revolving credit facility with substantially the same terms as our \$600 million credit facility.

As of December 31, 2006, the amount available to us under our credit facilities, net of outstanding letters of credit, was \$804.1 million. We believe these credit facilities, combined with our operating cash flows will be sufficient to fund our increased working capital needs. These facilities are described in further detail in Note 4 to the unaudited condensed consolidated financial statements.

### **Credit Ratings**

Our credit ratings directly affect our ability to obtain short-term and long-term financing, in addition to the cost of such financing. In determining our credit ratings, the rating agencies consider a number of quantitative factors, including debt to total capitalization, operating cash flow relative to outstanding debt, operating cash flow coverage of interest and pension liabilities and funding status. In addition, the rating agencies consider qualitative factors such as consistency of our earnings over time, the quality of our management and business strategy, the risks associated with our utility and nonutility businesses and the regulatory structures that govern our rates in the states where we operate.

Our debt is rated by three rating agencies: Standard & Poor’s Corporation (S&P), Moody’s Investors Service (Moody’s) and Fitch Ratings, Ltd. (Fitch). Our current debt ratings are all considered investment grade and are as follows:

	<u>S&amp;P</u>	<u>Moody’s</u>	<u>Fitch</u>
Unsecured senior long-term debt . . . . .	BBB	Baa3	BBB+
Commercial paper . . . . .	A-2	P-3	F-2

Currently, with respect to our unsecured senior long-term debt, S&P, Moody’s and Fitch maintain their stable outlook. None of our ratings are currently under review.

A credit rating is not a recommendation to buy, sell or hold securities. The highest investment grade credit rating for S&P is AAA, Moody’s is Aaa and Fitch is AAA. The lowest investment grade credit rating for S&P is BBB-, Moody’s is Baa3 and Fitch is BBB-. Our credit ratings may be revised or withdrawn at any time by the rating agencies, and each rating should be evaluated independent of any other rating. There can be no assurance that a rating will remain in effect for any given period of time or that a rating will not be lowered, or withdrawn entirely, by a rating agency if, in its judgment, circumstances so warrant.

**Debt Covenants**

We were in compliance with all of our debt covenants as of December 31, 2006. Our debt covenants are described in Note 4 to the unaudited condensed consolidated financial statements.

**Contractual Obligations and Commercial Commitments**

Significant commercial commitments are described in Note 8 to the unaudited condensed consolidated financial statements. There were no significant changes in our contractual obligations and commercial commitments during the three months ended December 31, 2006.

**Risk Management Activities**

We conduct risk management activities through both our utility and natural gas marketing segments. In our utility segment, we use a combination of storage, fixed physical contracts and fixed financial contracts to reduce our exposure to unusually large winter-period gas price increases. In our natural gas marketing segment, we manage our exposure to the risk of natural gas price changes and lock in our gross profit margin through a combination of storage and financial derivatives, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. To the extent our inventory cost and actual sales and actual purchases do not correlate with the changes in the market indices we use in our hedges, we could experience ineffectiveness or the hedges may no longer meet the accounting requirements for hedge accounting, resulting in the derivatives being treated as mark-to-market instruments through earnings.

We record our derivatives as a component of risk management assets and liabilities, which are classified as current or noncurrent based upon the anticipated settlement date of the underlying derivative. Substantially all of our derivative financial instruments are valued using external market quotes and indices. The following tables show the components of the change in the fair value of our utility and natural gas marketing commodity derivative contracts for the three months ended December 31, 2006 and 2005:

	Three Months Ended December 31, 2006		Three Months Ended December 31, 2005	
	Utility	Natural Gas Marketing	Utility	Natural Gas Marketing
	(In thousands)			
Fair value of contracts at beginning of period . . .	\$(27,209)	\$15,003	\$ 93,310	\$(61,898)
Contracts realized/settled . . . . .	(15,757)	45,899	29,955	(27,669)
Fair value of new contracts . . . . .	(1,910)	—	(2,101)	—
Other changes in value . . . . .	11,561	14,061	(82,891)	30,199
Fair value of contracts at end of period . . . . .	<u>\$(33,315)</u>	<u>\$74,963</u>	<u>\$ 38,273</u>	<u>\$(59,368)</u>

The fair value of our utility and natural gas marketing derivative contracts at December 31, 2006, is segregated below by time period and fair value source:

Source of Fair Value	Fair Value of Contracts at December 31, 2006				Total Fair Value
	Maturity in Years				
	Less than 1	1-3	4-5	Greater Than 5	
	(In thousands)				
Prices actively quoted . . . . .	\$34,974	\$ 9,257	\$—	\$—	\$44,231
Prices based on models and other valuation methods . . . . .	(1,393)	(1,190)	—	—	(2,583)
Total Fair Value . . . . .	<u>\$33,581</u>	<u>\$ 8,067</u>	<u>\$—</u>	<u>\$—</u>	<u>\$41,648</u>

### Storage and Hedging Outlook

AEM participates in transactions in which it seeks to find and profit from pricing differences that occur over time. AEM purchases physical natural gas and then sells financial contracts at advantageous prices to lock in a gross profit margin. AEM is able to capture gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time.

Natural gas inventory is marked to market at the end of each month with changes in fair value recognized as unrealized gains and losses in the period of change. Derivatives associated with our natural gas inventory, which are designated as fair value hedges, are marked to market each month based upon the NYMEX price with changes in fair value recognized as unrealized gains and losses in the period of change. The changes in the difference between the indices used to mark to market our physical inventory (Gas Daily) and the related fair-value hedge (NYMEX) is reported as a component of revenue and can result in volatility in our reported net income. Over time, gains and losses on the sale of storage gas inventory will be offset by gains and losses on the fair-value hedges; therefore, the economic gross profit AEM captured in the original transaction remains essentially unchanged.

AEM continually manages its positions to enhance the future economic profit it captured in the original transaction. Therefore, AEM may change its scheduled injection and withdrawal plans from one time period to another based on market conditions or adjust the amount of storage capacity it holds on a discretionary basis in an effort to achieve this objective. AEM monitors the impacts of these profit optimization efforts by estimating the economic gross profit that it captured through the purchase and sale of physical natural gas and the associated financial derivatives. The reconciliation below of the economic gross profit, combined with the effect of unrealized gains or losses recognized in accordance with generally accepted accounting principles in the financial statements in prior periods, is presented in order to provide a measure of the potential gross profit that could occur in future periods if AEM's optimization efforts are fully successful. We consider this measure of potential gross profit a non-GAAP financial measure as it is calculated using both forward-looking and historical financial information. The following table presents, by quarter, AEM's economic gross profit and its potential gross profit.

<u>Period Ending</u>	<u>Net Physical Position</u> (Bcf)	<u>Economic Gross Profit</u> (In millions)	<u>Associated Net Unrealized Gains (Losses)</u> (In millions)	<u>Potential Gross Profit</u> (In millions)
September 30, 2006 . . . . .	14.5	\$60.0	\$(16.0)	\$76.0
December 31, 2006 . . . . .	21.0	\$60.6	\$ 32.8	\$27.8

As of December 31, 2006, based upon AEM's derivatives position and inventory withdrawal schedule, the economic gross profit was \$60.6 million. In addition, \$32.8 million of net unrealized gains were recorded in the financial statements as of December 31, 2006. Therefore, the potential gross profit was \$27.8 million. The potential gross profit amount will not result in an equal increase in future net income as AEM will incur additional storage and other operational expenses to realize this amount.

The economic gross profit is based upon planned injection and withdrawal schedules, and the realization of the economic gross profit is contingent upon the execution of this plan, weather and other execution factors. Since AEM actively manages and optimizes its portfolio to enhance the future profitability of its storage position, it may change its scheduled injection and withdrawal plans from one time period to another based on market conditions. Therefore, we cannot ensure that the economic gross profit or the potential gross profit calculated as of December 31, 2006 will be fully realized in the future or in what time period. Further, if we experience operational or other issues which limit our ability to optimally manage our stored gas positions, our earnings could be adversely impacted.

### **Pension and Postretirement Benefits Obligations**

For the three months ended December 31, 2006 and 2005 our total net periodic pension and other benefits cost was \$12.1 million and \$12.5 million. All of these costs are recoverable through our gas utility rates; however, a portion of these costs is capitalized into our utility rate base. The remaining costs are recorded as a component of operation and maintenance expense.

The decrease in total net periodic pension and other benefits cost during the current-year period compared with the prior-year period primarily reflects changes in assumptions we made during our annual pension plan valuation completed June 30, 2006. The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. In the period leading up to our June 30, 2006 measurement date, these interest rates were increasing, which resulted in a 130 basis point increase in our discount rate used to determine our fiscal 2007 net periodic and post-retirement cost to 6.30 percent. This increase has the effect of decreasing the present value of our plan liabilities and associated expenses. This favorable impact was partially offset by the unfavorable impact of reducing the expected return on our pension plan assets by 25 basis points to 8.25 percent, which has the effect of increasing our pension and postretirement benefit cost.

During the three months ended December 31, 2006, we contributed \$2.8 million to our other postretirement plans, and we expect to contribute a total of approximately \$11 million to these plans during fiscal 2007.

## OPERATING STATISTICS AND OTHER INFORMATION

The following tables present certain operating statistics for our utility, natural gas marketing, pipeline and storage and other nonutility segments for the three-month periods ended December 31, 2006 and 2005.

### *Utility Sales and Statistical Data*

	Three Months Ended December 31	
	2006	2005
<b>METERS IN SERVICE, end of period</b>		
Residential . . . . .	2,915,864	2,910,467
Commercial . . . . .	277,684	279,263
Industrial . . . . .	3,023	3,074
Agricultural . . . . .	8,626	9,470
Public authority and other . . . . .	8,216	8,202
Total meters . . . . .	<u>3,213,413</u>	<u>3,210,476</u>
<b>INVENTORY STORAGE BALANCE — Bcf</b> . . . . .	60.3	59.6
<b>HEATING DEGREE DAYS<sup>(1)</sup></b>		
Actual (weighted average) . . . . .	1,135	1,056
Percent of normal . . . . .	101%	93%
<b>UTILITY SALES VOLUMES — MMcf<sup>(2)</sup></b>		
Gas sales volumes		
Residential . . . . .	50,699	53,709
Commercial . . . . .	27,085	29,139
Industrial . . . . .	5,735	9,009
Agricultural . . . . .	110	40
Public authority and other . . . . .	2,771	3,291
Total gas sales volumes . . . . .	86,400	95,188
Utility transportation volumes . . . . .	33,883	31,756
Total utility throughput . . . . .	<u>120,283</u>	<u>126,944</u>
<b>UTILITY OPERATING REVENUES (000's)<sup>(2)</sup></b>		
Gas sales revenues		
Residential . . . . .	\$ 574,736	\$ 783,346
Commercial . . . . .	283,033	424,338
Industrial . . . . .	53,983	128,471
Agricultural . . . . .	575	786
Public authority and other . . . . .	27,169	43,971
Total utility gas sales revenues . . . . .	939,496	1,380,912
Transportation revenues . . . . .	15,850	15,867
Other gas revenues . . . . .	8,898	8,231
Total utility operating revenues . . . . .	<u>\$ 964,244</u>	<u>\$1,405,010</u>
Utility average transportation revenue per Mcf . . . . .	\$ 0.47	\$ 0.50
Utility average cost of gas per Mcf sold . . . . .	\$ 8.12	\$ 11.82

See footnotes following these tables.

*Natural Gas Marketing, Pipeline and Storage and Other Nonutility Operations Sales and Statistical Data*

	Three Months Ended December 31	
	2006	2005
<b>CUSTOMERS, end of period</b>		
Industrial . . . . .	700	657
Municipal . . . . .	60	71
Other . . . . .	420	395
Total . . . . .	<u>1,180</u>	<u>1,123</u>
<b>INVENTORY STORAGE BALANCE — Bcf</b>		
Natural gas marketing . . . . .	21.2	15.7
Pipeline and storage . . . . .	2.7	2.4
Total . . . . .	<u>23.9</u>	<u>18.1</u>
<b>NATURAL GAS MARKETING SALES VOLUMES — MMcf<sup>(2)</sup></b> . . . . .	88,038	87,822
<b>PIPELINE TRANSPORTATION VOLUMES — MMcf<sup>(2)</sup></b> . . . . .	172,759	146,954
<b>OPERATING REVENUES (000's)<sup>(2)</sup></b>		
Natural gas marketing . . . . .	\$711,694	\$1,101,845
Pipeline and storage . . . . .	49,852	39,712
Other nonutility . . . . .	1,353	1,492
Total operating revenues . . . . .	<u>\$762,899</u>	<u>\$1,143,049</u>

Notes to preceding tables:

- (1) A heating degree day is equivalent to each degree that the average of the high and the low temperatures for a day is below 65 degrees. The colder the climate, the greater the number of heating degree days. Heating degree days are used in the natural gas industry to measure the relative coldness of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on 30-year average National Weather Service data for selected locations. For service areas that have weather normalized operations, normal degree days are used instead of actual degree days in computing the total number of heating degree days.
- (2) Sales volumes and revenues reflect segment operations, including intercompany sales and transportation amounts.

**Recent Ratemaking Developments**

The following describes the significant ratemaking developments that occurred during the three months ended December 31, 2006. The amounts described below represent the gross revenues that were requested or received in the rate filing, which may not necessarily reflect the increase in operating income obtained, as certain operating costs may have increased as a result of a commission's final ruling.

**Atmos Energy Colorado-Kansas Division.** In December 2006, the Colorado-Kansas Division filed its third annual ad valorem tax surcharge for \$1.5 million. The surcharge is designed to collect Kansas property taxes in excess of the amount included in Atmos' most recent general rate case. We began to bill this surcharge in January 2007.

**Atmos Energy Kentucky/Mid-States Division.** In April 2006, Atmos filed a rate case in its Missouri service area seeking a rate increase of \$3.4 million. The Company is proposing to consolidate the rates for its Missouri properties into three sets of regional rates and consolidate the current purchased gas adjustment (PGA) into one statewide PGA. The Company is also proposing a WNA mechanism. An evidentiary hearing was held in

November 2006. An order is expected to be issued in late February 2007 with any resulting change in rates effective in March 2007.

In November 2005, we received a notice from the TRA that it was opening an investigation into allegations by the Consumer Advocate and Protection Division of the Tennessee Attorney General's Office that we were overcharging customers in parts of Tennessee by approximately \$10 million per year. A hearing was held in August 2006. Of the \$10 million rate reduction requested by the Consumer Advocate and Protection Division, the TRA approved a \$6.1 million rate reduction in October 2006, that became effective in December 2006.

In February 2005, the Attorney General of the State of Kentucky filed a complaint with the Kentucky Public Service Commission (KPSC) alleging that our rates were producing revenues in excess of reasonable levels. We answered the complaint and filed a Motion to Dismiss with the KPSC. In February 2006, the KPSC issued an Order denying our Motion to Dismiss but stated that the Attorney General had not met his burden of proof concerning his complaint. In November 2006, we requested dismissal of the case through our filing a notice of intent to file a general rate case in December 2006. Upon receipt of the notice of intent, the KPSC suspended the procedural schedule until it issues a decision regarding the motion for dismissal. A hearing should be scheduled for early 2007. We believe that the Attorney General will not be able to demonstrate that our present rates are in excess of reasonable levels.

In December 2006, the Company filed a rate application for an increase in base rates of \$10.4 million in Kentucky. Additionally, we proposed to implement a process to review our rates annually and to collect the bad debt portion of gas costs directly rather than through the base rate. A decision is expected in the case in July 2007.

***Atmos Energy Louisiana Division.*** In May 2006, the LPSC voted to approve a settlement which included renewal of the RSC for both the LGS and TransLa service areas with provisions that will reduce regulatory lag. The first RSC filing was in August 2006 for approximately \$10.8 million, based on a test year ended December 31, 2005, for the LGS service area. The Company reached a settlement agreement on the case in December 2006 which resulted in an increase of \$9.5 million. The first filing for the TransLa service area for approximately \$1.8 million was made on December 28, 2006, for the test period ending September 30, 2006, with an effective rate adjustment of April 1, 2007.

***Atmos Energy Mid-Tex Division.*** During fiscal 2006, we received "show cause" resolutions from approximately 80 cities served by our Mid-Tex Division, including the City of Dallas, which require the Mid-Tex Division to demonstrate that the existing distribution rates are just and reasonable. In May 2006, the Mid-Tex Division filed a Statement of Intent with the Railroad Commission of Texas (RRC) which consolidated the "show cause" resolutions and seeks incremental annual revenues of approximately \$60 million and several rate design changes including WNA, revenue stabilization and recovery of the gas cost component of bad debt expense. In exchange for an agreement to provide the intervening parties in the case an additional two months to prepare for the hearing, the Mid-Tex Division obtained an agreement and approval to implement WNA in its rates for the 2006-2007 winter season and to implement WNA in the final rates in this proceeding. The hearing was completed on November 17, 2006. The hearing examiners in the case issued their Proposal for Decision (PFD) on February 2, 2007, which contained their recommendations to the RRC. In the PFD, the examiners recommended a total annual decrease in the Mid-Tex Division's rates of approximately \$22.8 million, a customer refund of \$2.6 million and a permanent weather normalization adjustment mechanism based on 10-year weather data. We are in the process of preparing our responses to the recommendations in the PFD. We continue to believe that the evidence presented in the case supports our request to increase rates in order to earn a fair rate of return. While the RRC is required by statute to issue its final decision by April 2, 2007, it could issue a final order sometime in March 2007. Any rate increase will be effective prospectively from the date of the final order; however, any rate decrease will be effective from May 31, 2006.

In September 2006, the Mid-Tex Division filed its annual gas cost reconciliation with the RRC. The filing reflects approximately \$24 million in refunds of amounts that were overcollected from customers between July 2005 and June 2006. The Mid-Tex Division received approval to refund these amounts over a six-month period which began in November 2006.

The Mid-Tex Division is also pursuing an appeal to the Travis County District Court of the Final Order in its last system-wide rate case completed in May 2004 to obtain a return of and on its investment associated with the Poly I replacement pipe that was originally disallowed in its rate case completed in May 2004. The Travis County District Court upheld the Commission's final order. An appeal to the Court of Appeals in Travis County has been prepared but no briefings or hearing schedule has been established.

## **RECENT ACCOUNTING DEVELOPMENTS**

Recent accounting developments and their impact on our financial position, results of operations and cash flows are described in Note 2 to the unaudited condensed consolidated financial statements.

### **Item 3. *Quantitative and Qualitative Disclosures About Market Risk***

Information regarding our quantitative and qualitative disclosures about market risk are disclosed in Item 7A in our annual report on Form 10-K for the year ended September 30, 2006. During the three months ended December 31, 2006, there were no material changes in our quantitative and qualitative disclosures about market risk.

### **Item 4. *Controls and Procedures***

As indicated in the certifications in Exhibit 31 of this report, the Company's Chief Executive Officer and Chief Financial Officer have evaluated the Company's disclosure controls and procedures as of December 31, 2006. Based on that evaluation, these officers have concluded that the Company's disclosure controls and procedures are effective in ensuring that material information required to be disclosed in this quarterly report is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. In addition, there were no changes during the Company's last fiscal quarter that materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

## **PART II. OTHER INFORMATION**

### **Item 1. *Legal Proceedings***

During the three months ended December 31, 2006, there were no material changes in the status of the litigation and environmental-related matters that were disclosed in Note 13 to our annual report on Form 10-K for the year ended September 30, 2006. We continue to believe that the final outcome of such litigation and environmental-related matters or claims will not have a material adverse effect on our financial condition, results of operations or net cash flows.

### **Item 6. *Exhibits***

A list of exhibits required by Item 601 of Regulation S-K and filed as part of this report is set forth in the Exhibits Index, which immediately precedes such exhibits.



## EXHIBITS INDEX

### Item 6(a)

<u>Exhibit Number</u>	<u>Description</u>	<u>Page Number</u>
12	Computation of ratio of earnings to fixed charges	
15	Letter regarding unaudited interim financial information	
31	Rule 13a-14(a)/15d-14(a) Certifications	
32	Section 1350 Certifications*	

\* These certifications, which were made pursuant to 18 U.S.C. Section 1350 by the Company's Chief Executive Officer and Chief Financial Officer, furnished as Exhibit 32 to this Quarterly Report on Form 10-Q, will not be deemed to be filed with the Commission or incorporated by reference into any filing by the Company under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent that the Company specifically incorporates such certifications by reference.